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AP-42, Fifth Edition, Volume I
Chapter 1: External Combustion Sources

Explanation of File Formats

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  EIIP Residential Wood Combustion Coordination Project. October 2003.
  Prepared for the Mid-Atlantic Regional Air Management Association
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URL: http://www.epa.gov/ttn/chief/ap42/ch01/

1.4   Natural Gas Combustion

1.4 FINAL SECTION

1.4.1   General[1-2]

Natural gas is one of the major combustion fuels used throughout the country. It is mainly used to generate industrial and utility electric power, produce industrial process steam and heat, and heat residential and commercial space. Natural gas consists of a high percentage of methane (generally above 85 percent) and varying amounts of ethane, propane, butane, and inerts (typically nitrogen, carbon dioxide, and helium). The average gross heating value of natural gas is approximately 1,020 British thermal units per standard cubic foot (Btu/scf), usually varying from 950 to 1,050 Btu/scf.

1.4.2   Firing Practices[3-5]

There are three major types of boilers used for natural gas combustion in commercial, industrial, and utility applications: watertube, firetube, and cast iron. Watertube boilers are designed to pass water through the inside of heat transfer tubes while the outside of the tubes is heated by direct contact with the hot combustion gases and through radiant heat transfer. The watertube design is the most common in utility and large industrial boilers. Watertube boilers are used for a variety of applications, ranging from providing large amounts of process steam, to providing hot water or steam for space heating, to generating high-temperature, high-pressure steam for producing electricity. Furthermore, watertube boilers can be distinguished either as field erected units or packaged units.

Field erected boilers are boilers that are constructed on site and comprise the larger sized watertube boilers. Generally, boilers with heat input levels greater than 100 MMBtu/hr, are field erected. Field erected units usually have multiple burners and, given the customized nature of their construction, also have greater operational flexibility and NO_x control options. Field erected units can also be further categorized as wall-fired or tangential-fired. Wall-fired units are characterized by multiple individual burners located on a single wall or on opposing walls of the furnace while tangential units have several rows of air and fuel nozzles located in each of the four corners of the boiler.

Package units are constructed off-site and shipped to the location where they are needed. While the heat input levels of packaged units may range up to 250 MMBtu/hr, the physical size of these units are constrained by shipping considerations and generally have heat input levels less than 100 MMBtu/hr. Packaged units are always wall-fired units with one or more individual burners. Given the size limitations imposed on packaged boilers, they have limited operational flexibility and cannot feasibly incorporate some NO_x control options.

Firetube boilers are designed such that the hot combustion gases flow through tubes, which heat the water circulating outside of the tubes. These boilers are used primarily for space heating systems, industrial process steam, and portable power boilers. Firetube boilers are almost exclusively packaged units. The two major types of firetube units are Scotch Marine boilers and the older firebox boilers. In cast iron boilers, as in firetube boilers, the hot gases are contained inside the tubes and the water being heated circulates outside the tubes. However, the units are constructed of cast iron rather than steel. Virtually all cast iron boilers are constructed as package boilers. These boilers are used to produce either low-pressure steam or hot water, and are most commonly used in small commercial applications.

Natural gas is also combusted in residential boilers and furnaces. Residential boilers and furnaces generally resemble firetube boilers with flue gas traveling through several channels or tubes with water or air circulated outside the channels or tubes.

1.4.3 Emissions[3-4]

The emissions from natural gas-fired boilers and furnaces include nitrogen oxides (NO_x), carbon monoxide (CO), and carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), volatile organic compounds (VOCs), trace amounts of sulfur dioxide (SO_2), and particulate matter (PM).

Nitrogen Oxides -

Nitrogen oxides formation occurs by three fundamentally different mechanisms. The principal mechanism of NO_x formation in natural gas combustion is thermal NO_x. The thermal NO_x mechanism occurs through the thermal dissociation and subsequent reaction of nitrogen (N_2) and oxygen (O_2) molecules in the combustion air. Most NO_x formed through the thermal NO_x mechanism occurs in the high temperature flame zone near the burners. The formation of thermal NO_x is affected by three furnace-zone factors: (1) oxygen concentration, (2) peak temperature, and (3) time of exposure at peak temperature. As these three factors increase, NO_x emission levels increase. The emission trends due to changes in these factors are fairly consistent for all types of natural gas-fired boilers and furnaces. Emission levels vary considerably with the type and size of combustor and with operating conditions (e.g., combustion air temperature, volumetric heat release rate, load, and excess oxygen level).

The second mechanism of NO_x formation, called prompt NO_x, occurs through early reactions of nitrogen molecules in the combustion air and hydrocarbon radicals from the fuel. Prompt NO_x reactions occur within the flame and are usually negligible when compared to the amount of NO_x formed through the thermal NO_x mechanism. However, prompt NO_x levels may become significant with ultra-low-NO_x burners.

The third mechanism of NO_x formation, called fuel NO_x, stems from the evolution and reaction of fuel-bound nitrogen compounds with oxygen. Due to the characteristically low fuel nitrogen content of natural gas, NO_x formation through the fuel NO_x mechanism is insignificant.

Carbon Monoxide -

The rate of CO emissions from boilers depends on the efficiency of natural gas combustion. Improperly tuned boilers and boilers operating at off-design levels decrease combustion efficiency resulting in increased CO emissions. In some cases, the addition of NO_x control systems such as low NO_x burners and flue gas recirculation (FGR) may also reduce combustion efficiency, resulting in higher CO emissions relative to uncontrolled boilers.

Volatile Organic Compounds -

The rate of VOC emissions from boilers and furnaces also depends on combustion efficiency. VOC emissions are minimized by combustion practices that promote high combustion temperatures, long residence times at those temperatures, and turbulent mixing of fuel and combustion air. Trace amounts of VOC species in the natural gas fuel (e.g., formaldehyde and benzene) may also contribute to VOC emissions if they are not completely combusted in the boiler.

Sulfur Oxides -

Emissions of SO_2 from natural gas-fired boilers are low because pipeline quality natural gas typically has sulfur levels of 2,000 grains per million cubic feet. However, sulfur-containing odorants are added to natural gas for detecting leaks, leading to small amounts of SO_2 emissions. Boilers combusting unprocessed natural gas may have higher SO_2 emissions due to higher levels of sulfur in the natural gas. For these units, a sulfur mass balance should be used to determine SO_2 emissions.

Particulate Matter -

Because natural gas is a gaseous fuel, filterable PM emissions are typically low. Particulate matter from natural gas combustion has been estimated to be less than 1 micrometer in size and has filterable and condensable fractions. Particulate matter in natural gas combustion are usually larger molecular weight hydrocarbons that are not fully combusted. Increased PM emissions may result from poor air/fuel mixing or maintenance problems.

Greenhouse Gases -[6-9]

CO_2, CH_4, and N_2O emissions are all produced during natural gas combustion. In properly tuned boilers, nearly all of the fuel carbon (99.9 percent) in natural gas is converted to CO_2 during the combustion process. This conversion is relatively independent of boiler or combustor type. Fuel carbon not converted to CO_2 results in CH_4, CO, and/or VOC emissions and is due to incomplete combustion. Even in boilers operating with poor combustion efficiency, the amount of CH_4, CO, and VOC produced is insignificant compared to CO_2 levels.

Formation of N_2O during the combustion process is affected by two furnace-zone factors. N_2O emissions are minimized when combustion temperatures are kept high (above 1475°F) and excess oxygen is kept to a minimum (less than 1 percent).

Methane emissions are highest during low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of methane.

1.4.4 Controls[4,10]

NO_x Controls -

Currently, the two most prevalent combustion control techniques used to reduce NO_x emissions from natural gas-fired boilers are flue gas recirculation (FGR) and low NO_x burners. In an FGR system, a portion of the flue gas is recycled from the stack to the burner windbox. Upon entering the windbox, the recirculated gas is mixed with combustion air prior to being fed to the burner. The recycled flue gas consists of combustion products which act as inerts during combustion of the fuel/air mixture. The FGR system reduces NO_x emissions by two mechanisms. Primarily, the recirculated gas acts as a diluent to reduce combustion temperatures, thus suppressing the thermal NO_x mechanism. To a lesser extent, FGR also reduces NO_x formation by lowering the oxygen concentration in the primary flame zone. The amount of recirculated flue gas is a key operating parameter influencing NO_x emission rates for these systems. An FGR system is normally used in combination with specially designed low NO_x burners capable of sustaining a stable flame with the increased inert gas flow resulting from the use of FGR. When low NO_x burners and FGR are used in combination, these techniques are capable of reducing NO_x emissions by 60 to 90 percent.

Low NO_x burners reduce NO_x by accomplishing the combustion process in stages. Staging partially delays the combustion process, resulting in a cooler flame which suppresses thermal NO_x formation. The two most common types of low NO_x burners being applied to natural gas-fired boilers are staged air burners and staged fuel burners. NO_x emission reductions of 40 to 85 percent (relative to uncontrolled emission levels) have been observed with low NO_x burners.

Other combustion control techniques used to reduce NO_x emissions include staged combustion and gas reburning. In staged combustion (e.g., burners-out-of-service and overfire air), the degree of staging is a key operating parameter influencing NO_x emission rates. Gas reburning is similar to the use of overfire

in the use of combustion staging. However, gas reburning injects additional amounts of natural gas in the upper furnace, just before the overfire air ports, to provide increased reduction of NO_x to NO_2.

Two postcombustion technologies that may be applied to natural gas-fired boilers to reduce NO_x emissions are selective noncatalytic reduction (SNCR) and selective catalytic reduction (SCR). The SNCR system injects ammonia (NH_3) or urea into combustion flue gases (in a specific temperature zone) to reduce NO_x emission. The Alternative Control Techniques (ACT) document for NO_x emissions from utility boilers, maximum SNCR performance was estimated to range from 25 to 40 percent for natural gas-fired boilers.[12] Performance data available from several natural gas fired utility boilers with SNCR show a 24 percent reduction in NO_x for applications on wall-fired boilers and a 13 percent reduction in NO_x for applications on tangential-fired boilers.[11] In many situations, a boiler may have an SNCR system installed to trim NO_x emissions to meet permitted levels. In these cases, the SNCR system may not be operated to achieve maximum NO_x reduction. The SCR system involves injecting NH_3 into the flue gas in the presence of a catalyst to reduce NO_x emissions. No data were available on SCR performance on natural gas fired boilers at the time of this publication. However, the ACT Document for utility boilers estimates NO_x reduction efficiencies for SCR control ranging from 80 to 90 percent.[12]

Emission factors for natural gas combustion in boilers and furnaces are presented in Tables 1.4-1, 1.4-2, 1.4-3, and 1.4-4.[11] Tables in this section present emission factors on a volume basis (lb/10^6 scf). To convert to an energy basis (lb/MMBtu), divide by a heating value of 1,020 MMBtu/10^6 scf. For the purposes of developing emission factors, natural gas combustors have been organized into three general categories: large wall-fired boilers with greater than 100 MMBtu/hr of heat input, boilers and residential furnaces with less than 100 MMBtu/hr of heat input, and tangential-fired boilers. Boilers within these categories share the same general design and operating characteristics and hence have similar emission characteristics when combusting natural gas.

Emission factors are rated from A to E to provide the user with an indication of how "good" the factor is, with "A" being excellent and "E" being poor. The criteria that are used to determine a rating for an emission factor can be found in the Emission Factor Documentation for AP-42 Section 1.4 and in the introduction to the AP-42 document.

1.4.5   Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section are summarized below. For further detail, consult the Emission Factor Documentation for this section. These and other documents can be found on the Emission Factor and Inventory Group (EFIG) home page (http://www.epa.gov/ttn/chief).

Supplement D, March 1998

☐   Text was revised concerning Firing Practices, Emissions, and Controls.

☐   All emission factors were updated based on 482 data points taken from 151 source tests. Many new emission factors have been added for speciated organic compounds, including hazardous air pollutants.

July 1998 - minor changes

☐   Footnote D was added to table 1.4-3 to explain why the sum of individual HAP may exceed VOC or TOC, the web address was updated, and the references were reordered.

Table 1.4-1. EMISSION FACTORS FOR NITROGEN OXIDES (NO$_x$) AND CARBON MONOXIDE (CO) FROM NATURAL GAS COMBUSTION[a]

Combustor Type (MMBtu/hr Heat Input) [SCC]	NO$_x$[b]		CO	
	Emission Factor (lb/10^6 scf)	Emission Factor Rating	Emission Factor (lb/10^6 scf)	Emission Factor Rating
Large Wall-Fired Boilers (>100) [1-01-006-01, 1-02-006-01, 1-03-006-01]				
Uncontrolled (Pre-NSPS)[c]	280	A	84	B
Uncontrolled (Post-NSPS)[c]	190	A	84	B
Controlled - Low NO$_x$ burners	140	A	84	B
Controlled - Flue gas recirculation	100	D	84	B
Small Boilers (<100) [1-01-006-02, 1-02-006-02, 1-03-006-02, 1-03-006-03]				
Uncontrolled	100	B	84	B
Controlled - Low NO$_x$ burners	50	D	84	B
Controlled - Low NO$_x$ burners/Flue gas recirculation	32	C	84	B
Tangential-Fired Boilers (All Sizes) [1-01-006-04]				
Uncontrolled	170	A	24	C
Controlled - Flue gas recirculation	76	D	98	D
Residential Furnaces (<0.3) [No SCC]				
Uncontrolled	94	B	40	B

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. Emission factors are based on an average natural gas higher heating value of 1,020 Btu/scf. To convert from lb/10^6 scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. SCC = Source Classification Code. ND = no data. NA = not applicable.

[b] Expressed as NO$_2$. For large and small wall fired boilers with SNCR control, apply a 24 percent reduction to the appropriate NO$_x$ emission factor. For tangential-fired boilers with SNCR control, apply a 13 percent reduction to the appropriate NO$_x$ emission factor.

[c] NSPS=New Source Performance Standard as defined in 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction modification, or reconstruction after June 19, 1984.

TABLE 1.4-2. EMISSION FACTORS FOR CRITERIA POLLUTANTS AND GREENHOUSE GASES FROM NATURAL GAS COMBUSTION[a]

Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
CO_2[b]	120,000	A
Lead	0.0005	D
N_2O (Uncontrolled)	2.2	E
N_2O (Controlled-low-NO_X burner)	0.64	E
PM (Total)[c]	7.6	D
PM (Condensable)[c]	5.7	D
PM (Filterable)[c]	1.9	B
SO_2[d]	0.6	A
TOC	11	B
Methane	2.3	B
VOC	5.5	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from $lb/10^6$ scf to $kg/10^6$ m^3, multiply by 16. To convert from $lb/10^6$ scf to lb/MMBtu, divide by 1,020. The emission factors in this table may be converted to other natural gas heating values by multiplying the given emission factor by the ratio of the specified heating value to this average heating value. TOC = Total Organic Compounds. VOC = Volatile Organic Compounds.

[b] Based on approximately 100% conversion of fuel carbon to CO_2. CO_2[$lb/10^6$ scf] = (3.67) (CON) (C)(D), where CON = fractional conversion of fuel carbon to CO_2, C = carbon content of fuel by weight (0.76), and D = density of fuel, $4.2x10^4$ $lb/10^6$ scf.

[c] All PM (total, condensible, and filterable) is assumed to be less than 1.0 micrometer in diameter. Therefore, the PM emission factors presented here may be used to estimate PM_{10}, $PM_{2.5}$ or PM_1 emissions. Total PM is the sum of the filterable PM and condensible PM. Condensible PM is the particulate matter collected using EPA Method 202 (or equivalent). Filterable PM is the particulate matter collected on, or prior to, the filter of an EPA Method 5 (or equivalent) sampling train.

[d] Based on 100% conversion of fuel sulfur to SO_2. Assumes sulfur content is natural gas of 2,000 grains/10^6 scf. The SO_2 emission factor in this table can be converted to other natural gas sulfur contents by multiplying the SO_2 emission factor by the ratio of the site-specific sulfur content (grains/10^6 scf) to 2,000 grains/10^6 scf.

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor ($lb/10^6$ scf)	Emission Factor Rating
91-57-6	2-Methylnaphthalene[b,c]	2.4E-05	D
56-49-5	3-Methylchloranthrene[b,c]	<1.8E-06	E
	7,12-Dimethylbenz(a)anthracene[b,c]	<1.6E-05	E
83-32-9	Acenaphthene[b,c]	<1.8E-06	E
203-96-8	Acenaphthylene[b,c]	<1.8E-06	E
120-12-7	Anthracene[b,c]	<2.4E-06	E
56-55-3	Benz(a)anthracene[b,c]	<1.8E-06	E
71-43-2	Benzene[b]	2.1E-03	B
50-32-8	Benzo(a)pyrene[b,c]	<1.2E-06	E
205-99-2	Benzo(b)fluoranthene[b,c]	<1.8E-06	E
191-24-2	Benzo(g,h,i)perylene[b,c]	<1.2E-06	E
205-82-3	Benzo(k)fluoranthene[b,c]	<1.8E-06	E
106-97-8	Butane	2.1E+00	E
218-01-9	Chrysene[b,c]	<1.8E-06	E
53-70-3	Dibenzo(a,h)anthracene[b,c]	<1.2E-06	E
25321-22-6	Dichlorobenzene[b]	1.2E-03	E
74-84-0	Ethane	3.1E+00	E
206-44-0	Fluoranthene[b,c]	3.0E-06	E
86-73-7	Fluorene[b,c]	2.8E-06	E
50-00-0	Formaldehyde[b]	7.5E-02	B
110-54-3	Hexane[b]	1.8E+00	E
193-39-5	Indeno(1,2,3-cd)pyrene[b,c]	<1.8E-06	E
91-20-3	Naphthalene[b]	6.1E-04	E
109-66-0	Pentane	2.6E+00	E
85-01-8	Phenanathrene[b,c]	1.7E-05	D

TABLE 1.4-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS FROM
NATURAL GAS COMBUSTION (Continued)

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
74-98-6	Propane	1.6E+00	E
129-00-0	Pyrene[b,c]	5.0E-06	E
108-88-3	Toluene[b]	3.4E-03	C

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. To convert from lb/10^6 scf to lb/MMBtu, divide by 1,020. Emission Factors preceeded with a less-than symbol are based on method detection limits.

[b] Hazardous Air Pollutant (HAP) as defined by Section 112(b) of the Clean Air Act.

[c] HAP because it is Polycyclic Organic Matter (POM). POM is a HAP as defined by Section 112(b) of the Clean Air Act.

[d] The sum of individual organic compounds may exceed the VOC and TOC emission factors due to differences in test methods and the availability of test data for each pollutant.

TABLE 1.4-4. EMISSION FACTORS FOR METALS FROM NATURAL GAS COMBUSTION[a]

CAS No.	Pollutant	Emission Factor (lb/10^6 scf)	Emission Factor Rating
7440-38-2	Arsenic[b]	2.0E-04	E
7440-39-3	Barium	4.4E-03	D
7440-41-7	Beryllium[b]	<1.2E-05	E
7440-43-9	Cadmium[b]	1.1E-03	D
7440-47-3	Chromium[b]	1.4E-03	D
7440-48-4	Cobalt[b]	8.4E-05	D
7440-50-8	Copper	8.5E-04	C
7439-96-5	Manganese[b]	3.8E-04	D
7439-97-6	Mercury[b]	2.6E-04	D
7439-98-7	Molybdenum	1.1E-03	D
7440-02-0	Nickel[b]	2.1E-03	C
7782-49-2	Selenium[b]	<2.4E-05	E
7440-62-2	Vanadium	2.3E-03	D
7440-66-6	Zinc	2.9E-02	E

[a] Reference 11. Units are in pounds of pollutant per million standard cubic feet of natural gas fired. Data are for all natural gas combustion sources. Emission factors preceeded by a less-than symbol are based on method detection limits. To convert from lb/10^6 scf to kg/10^6 m^3, multiply by 16. To convert from lb/10^6 scf to lb/MMBtu, divide by 1,020.

[b] Hazardous Air Pollutant as defined by Section 112(b) of the Clean Air Act.

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11.   *Emission Factor Documentation for AP-42 Section 1.4—Natural Gas Combustion*, Technical Support Division, Office of Air Quality Planning and Standards, U. S. Environmental Protection Agency, Research Triangle Park, NC, 1997.

12.   *Alternate Control Techniques Document - NO_x Emissions from Utility Boilers*, EPA-453/R-94-023, U. S. Environmental Protection Agency, Research Triangle Park, NC, March 1994.

AP-42 Section 1.4: Natural Gas Combustion Data Files

The data that supports the emission factors are presented in summary in the background report and are reported more completely in an electronic database. The database is in Microsoft Access 97®. The file is located on the CHIEF web site at http://www.epa.gov/ttn/chief/ap42c1.html.

1.4 BACKGROUND DOCUMENT

EMISSION FACTOR DOCUMENTATION
FOR AP-42 SECTION 1.4 NATURAL GAS COMBUSTION

Prepared for:

Office of Air Quality Planning and Standards
U.S. Environmental Protection Agency
Research Triangle Park, NC

Prepared by:

Eastern Research Group
1600 Perimeter Park
Morrisville, NC 27560

March 1998

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TABLES

Emission Factor Documentation for AP-42 Section 1.4
Natural Gas Combustion

1.0 Introduction

The revised AP-42 section described in this report replaces the section published in September 1996 as Supplement B to the Fifth Edition. This background report replaces the Emission Factor (EMF) Documentation for AP-42 Section 1.4, Natural Gas Combustion, issued April 1993. The purpose of this background report is to provide technical documentation supporting the Supplement D revisions to AP-42 Section 1.4.

The EPA publishes emission factors in its Compilation of Air Pollutant Emission Factors, EPA Publication No. AP-42 (AP-42). The document has been published since 1972 as the primary compilation of EPA's emission factor information. Federal, State and local agencies, consultants, and industry use the document to identify major contributors of atmospheric pollutants, develop emission control strategies, determine applicability of permitting programs, and compile emission inventories for ambient air impact analyses and State Implementation Plans (SIPs). Volume 1, Stationary Sources is published by Emission Factor Inventory Group (EFIG) in EPA's Office of Air Quality Planning and Standards (OAQPS).

1.1 Reasons For Updating

The Clean Air Act Amendments of 1990 added greatly to the number of air pollution sources for which emission factor development was required, and also called for the improvement of existing factors. There are several reasons for updating or revising AP-42 sections and emission factors.

☐ New Standard. After the proposal of a standard, the EPA reviews the available material to determine if sufficient information has been gathered to support the development of emission factors for the industry or process being studied. Oftentimes, the proposal or development of a new standard for a source or source category will trigger a re-evaluation of emission factors for a particular source. In the proposal of a standard, the proposal team gathers tremendous amounts of data to support the standard, much more data than is typically gathered for AP-42. The proposal team may compare their new data with existing information used to develop AP-42 emission factors. If, in the comparison, the team discovers a deficiency in the existing information, they may turn their data over to EFIG, who in turn may use the information to improve emission factors.

☐ Outside Requests. The EPA receives requests for better source and emission factor information. Requests may come from other Office of Air Quality Planning and Standards (OAQPS) branches, EPA laboratories and regional offices, State agencies, trade associations, special interest groups, or private individuals. The requests may take the form of directives, letters, oral inquiries, or comments on published emission factors.

☐ Improvement of the National Inventory. The EPA may determine that a particular source category is a significant contributor to the National Inventory and that EPA should develop or improve emission factors.

☐ New Information. New information will be useful that may have been developed initially for Emission Standards Division (ESD) background documents involving new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), and Control Techniques Guidelines (CTG), and reports by various EPA laboratories.

☐ Contractor Expertise. A contractor or consultant may have gained expertise on a source category during previous work, either for EPA or for other clients, and may warrant considering a relatively low-expense update and expansion of available information.

Section 1.4 has been updated to incorporate new available data on this source category. New information has been used to better characterize this source category, develop improved volatile organic compound (VOC) and particulate matter (PM) emission factors, and update criteria pollutant emission factors. In response to the upcoming NESHAP for this source category, an expanded hazardous air pollutant (HAP) emission factor list has also been provided.

This background report consists of four sections. This introduction provides background information on AP-42 and documents such as this one that are issued to update sections of AP-42. Section 2 presents the data search and screening steps, discusses the references used to revise AP-42 Section 1.4, and defines the emissions data quality rating system. Section 3 discusses overall revisions to AP-42 Section 1.4, provides details about the database built for storing the available data, presents the calculations used to calculate emission factors, and defines the emission factor quality rating system. Section 4 presents the proposed revision of the existing AP-42 section as it would appear in Supplement D.

1.2   References For Section 1

1.   Procedures For Preparing Emission Factor Documents, Third Revised Draft Version, Office Of Air Quality Planning And Standards, U.S. EPA, Research Triangle Park, NC 27711, November 1996.

2.0 Literature Search and Screening

Data used in this section were obtained from a number of sources within OAQPS and from outside organizations. The AP-42 background files were reviewed for information on these sources, demonstrated pollution control technologies, and emissions data. The Factor Information Retrieval System (FIRE) was searched for emission data on natural gas-fired combustion sources. The Source Test Information Retrieval System (STIRS) data set, compiled by EFIG, was reviewed and provided emissions data from several sources. The STIRS data set is a collection of emission test reports that have been scanned and stored on CD-ROM.

In the review of available references, emissions data were accepted if:

☐   sufficient information about the combustion source and any pollution control devices was given.

☐   the test report identified if the emissions tests were conducted before or after a pollution control device.

☐   emission levels were measured by currently accepted test methods.

☐   emission test results were reported in units which could be converted into the reporting units selected for this AP-42 section.

☐   sufficient data existed to characterize operating conditions.

2.1 Emission Data Quality Rating System[1]

After reviewing the test reports, it should be possible to assign a data quality rating to each pollutant emission rate for each test series. The individual data quality ratings are not to be confused with the overall emission factor ratings. The data quality ratings are an appraisal of the reliability of the basic emission data that will be used to later develop the factor.

Test data quality is rated A through D, based on the following criteria:

A -   Tests are performed by a sound methodology and are reported in enough detail for adequate validation.

B -   Tests are performed by a generally sound methodology, but lacking enough detail for adequate validation.

C -   Tests are based on an unproven or new methodology, or are lacking a significant amount of background information.

D -   Tests are based on a generally unacceptable method, but the method may provide an order-of-magnitude value for the source.

The quality rating of test data helps identify good data, even when it is not possible to extract a factor representative of a typical source in the category from those data. For example, the data from a given test may be good enough for a data quality rating of "A," but the test may be for a unique feed material, or the production specifications may be either more or less stringent than at the typical facility.

In following the general guidelines discussed above, four specific criteria can be considered to evaluate the emission data to ensure that the data are based on a sound methodology, and documentation provides adequate detail. A test series is initially rated "A through D" in each of the following four areas.

☐   <u>Source operation</u>. If the manner in which the source was operated is well documented in the report, and the source was operating within typical parameters during the test, an A rating should be assigned. If the report stated parameters were typical, but lacked detailed information, a B rating is assigned. If there is reason to believe operation was not typical, a C or D rating is assigned.

☐   <u>Test method and sampling procedures</u>. In developing ratings, the accuracy of the test method as well as the adequacy of the documentation are considered. In general, if a current EPA reference test method appropriate for the source was followed, the rating should be higher (A or B). If other methods are used, an assessment is made of their validity. If it is judged that the method was likely to be inaccurate or biased, a lower rating (C or D) is given. A complete report should indicate whether any procedures deviated from standard methods and explain any deviations. If deviations were reported, an evaluation is made of whether these were likely to influence the test results.

☐   <u>Sampling and process data</u>. During testing, many variations can occur without warning and sometimes without being noticed. Such variations can induce wide deviations in sampling results. If a large spread between test run results cannot be explained by information contained in the site test report or from test reports of other sources, the data are suspect and are given a lower rating. However, it should be recognized that a process may have highly variable emissions and a lower rating may not be appropriate solely on the basis of wide deviations in sampling results.

☐   <u>Analysis and calculations</u>. Ideally, test reports should contain original raw data sheets and other QA documentation. If there are data sheets, the nomenclature and equations used are compared with those specified by EPA to establish equivalency. The depth of review of the calculations is dictated by the reviewers' confidence in the ability and conscientiousness of the tester, based on such factors as consistency of results and completeness of other areas of the test report. Reports may indicate that raw data sheets were available but were not included. If the test report is of high quality based on the other criteria, the quality rating should not be lowered due to a lack of data sheets.

An overall emission data quality rating is developed considering the scores on the four criteria. There is no precise equation for the relative weighting of the factors, because each report presents different issues, and the rating system needs to provide flexibility to consider the strengths and weaknesses of each test series and reach a judgment on the overall rating. However, the two criteria concerning (1) the test method and sampling procedures and (2) the sampling and process data should be

weighted most heavily. If either of these two criteria are assigned a low rating, this low rating should be assigned as the overall data quality rating, no matter how complete the documentation is.

2.2   Review of Data Sets

A total of 42 documents were reviewed in the process of developing emission factors for this revision to AP-42 Section 1.4, Natural Gas Combustion. A summary review of the references used to develop emission factors and their associated database identification numbers is presented in Table 2-1, following this section. The majority of the references which were used to revise the emission factors for natural gas combustion sources were either compliance test reports or summaries of compliance test results. Seven of the references used in the development of this data were the results of research or specific information gathering efforts. Furthermore, NO_x emission factors for several natural gas combustion sources were developed from an electronic database received from the Acid Rain Division (ARD) of EPA. The data received from the ARD, and the corresponding emission factor averages, are presented in Appendix A.

References 2 Through 6, 8, and 41

References 2 through 6, reference 8, and reference 41 are the results of several research or specific information gathering efforts on natural gas-fired boilers. The data extracted from these reports make up the vast majority of all the HAP information contained in the revision of AP-42 Section 1.4. Pollutants tested in references 2, 3, and 41 also included speciated polycyclic aromatic hydrocarbons (PAH) and speciated metals. The test results reported in these references were all from emission measurements conducted on tangential- and wall-fired utility boilers. Most of the sources detailed in these references were uncontrolled, however, some incorporated flue gas recirculation (FGR) for NO_x control. All of the emission test data contained in these references were assigned a rating of A due to the detailed information provided.

References 7, 9 Through 40, and 43 Through 44

These references were all compliance test results from both utility and industrial boilers firing natural gas. The majority of these compliance tests focused on NO_x and CO emissions, however, several tests included results of total hydrocarbon (THC), non-methane hydrocarbon (NMHC), methane, and particulate matter (PM) measurements. Some of the boilers reported in these references were operated with low-NO_x burners, FGR, or selective non-catalytic reduction (SNCR) for NO_x control. All of the emission test data contained in these references were assigned a rating of A due to the detailed information provided.

Reference 42

Reference 42 is a NO_x emission summary for all national gas-fired utility boilers required to submit CEM data to the ARD as required by Title IV of the Clear Air Act Amendments. These data represent average NO_x emissions from these boilers for the 3rd quarter of 1996. This data set included NO_x emissions from 121 wall-fired boilers, 62 tangential-fired boilers, and five wall-fired boilers with low-NO_x burners. The data received from ARD, and the corresponding emission factor averages, are presented in Appendix A.

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
2	Source Test on a Tangential-Fired Utility Boiler	NO_x, CO, speciated HAP's, metals	A	1
3	Source Test on a Wall-Fired Utility Boiler	NO_x, CO, speciated HAP's, metals	A	2
4	Source Test on a Wall-Fired Utility Boiler	Benzene, Formaldehyde	A	3
5	Source Test on a Wall-Fired Utility Boiler	Benzene, Formaldehyde	A	4
6	Source Test on a Package Boiler	NO_x, CO, Methane, Ethane, PM	A	6
7	Compliance Test on a Package Boiler	NO_x, CO	A	7
8	Source Tests on Seven Wall-Fired Utility Boilers	Benzene, Formaldehyde	A	8, 9, 10, 11, 12, 13, 14
9	Source Test on a Wall-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	15
10	Compliance Test on a Wall-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	23
11	Compliance Test on Two Tangential-Fired Utility Boilers With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	17
12	Compliance Test on Two Wall-Fired Utility Boilers With SNCR Control	NO_x, CO, Hydrocarbons	A	18
13	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons, PM	A	19
14	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons	A	20
15	Compliance Test on a Tangential-Fired Utility Boiler With SNCR Control	NO_x, CO, Hydrocarbons	A	22
16	Compliance Test on a Wall-Fired Utility Boiler	NO_x, CO, Hydrocarbons	A	16
17	Compliance Test on a Tangential-Fired Utility Boiler With SNCR	NO_x, CO, Hydrocarbons	A	21

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
18	Compliance Test on a Boiler	NO_x, CO	A	106
19	Compliance Test on a Boiler	NO_x, CO	A	107
20	Compliance Test on a Boiler	NO_x, CO	A	108
21	Compliance Test on Two Boilers	NO_x, CO	A	109
22	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	110
23	Compliance Test on Two Boilers	NO_x	A	111
24	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	112
25	Compliance Test on Two Boilers	NO_x	A	113
26	Compliance Test on a Boiler	NO_x, CO, PM	A	114
27	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	115
28	Compliance Test on a Boiler	NO_x, CO	A	116
29	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	117
30	Compliance Test on a Boiler	NO_x	A	119
31	Source Test on a Boiler	NO_x, CO	A	120
32	Source Test on a Boiler	NO_x, CO, Hydrocarbons, PM	A	121
33	Compliance Test on a Boiler	NO_x	A	122
34	Compliance Test on a Boiler	NO_x	A	123
35	Compliance Test on a Boiler	NO_x, CO	A	125
36	Compliance Test on Two Boilers	NO_x, CO	A	126
37	Compliance Test on a Boiler	PM	A	131
38	Compliance Test on a Boiler	NO_x, PM	A	132

Table 2.2-1. SUMMARY OF REFERENCES USED IN THE REVISION OF SECTION 1.4
(Continued)

Reference Number[a]	General Information Concerning Document	Pollutants Tested	Data Quality	Database I.D.
39	Compliance Test on a Boiler	NO_x, CO, Hydrocarbons	A	133
40	Compliance Test on Four Boilers	NO_x, CO, Hydrocarbons	A	134
41	Source Tests on Two Wall-Fired and Two Tangential-Fired Boilers	NO_x, CO, speciated HAP's, metals	A	200
42	CEM Data Submitted to ARD	NO_x,	A	Not in Database
43	Compliance Test on One Boiler	PM	A	201
44	Compliance Test on One Boiler	PM	A	202

[a]Reference number corresponds to the reference listing at the end of this section.

2.3   References For Section 2

1.   Procedures for Preparing Emission Factor Documents, Third Revised Draft Version, Office of
      Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, NC 27711,
      November 1996.

2.   *PICES Field Chemical Emissions Monitoring Project Site 120 Emissions Report.* Carnot, Tustin,
      CA, December 1995.

3.   *PICES Field Chemical Emissions Monitoring Project Site 121 Emissions Report.* Carnot, Tustin,
      CA, December 1995.

4.   *Emission Inventory Testing at El Segundo Generating Station No. 1 for Southern California
      Edison Company*, Carnot, April 1990.

5.   *Air Toxics Emissions Inventory Testing at Alamitos Unit 5*, Carnot, May 1990.

6.   *Gas Research Institute/WP Natural Gas @ Boise Cascade Timber and Wood Products Division
      #2 Package Boiler*, Amtest Air Quality, Inc., May 1995.

7.   *Source Test For Measurement Of Nitrogen Oxides And Carbon Monoxide Emissions From
      Boiler Exhaust At GAF Building Materials*, Pacific Environmental Services, Inc., Baldwin Park,
      CA, May 1991.

8.   *Field Chemical Emissions Monitoring Project: Emissions Report For Sites 103 - 109.
      Preliminary Draft Report.* Radian Corporation, Austin, TX, March 1993. (EPRI Report)

9.   *Urea Permit Compliance Testing at Alamitos Generation Station Unit 2*, Carnot, November
      1992.

10.   *Emissions Source Test Report For Urea Injection Compliance Testing Huntington Beach Unit 1
      Permit Application No. R-249463*, Geraghty & Miller, March 1994.

11.   *SCE Etiwanda Units 1 and 2 Urea Compliance Source Test Report, Final Report, Volume 1 of II*,
      Radian Corporation, March 1994.

12.   *Source Test Report For Urea Permit Compliance Testing Redondo Beach Generating Station
      Units 5 and 6*, Sierra Environmental Engineering, Inc., October 1992.

13.   *Urea Permit Compliance Testing at Alamitos Generation Station Unit 4*, Carnot, April 1993.

14.   *Urea Permit Compliance Testing at El Segundo Generating Station Unit 3*, Carnot,
      September 1993.

15.   *Emissions Source Test Report For Recirculation Gas By-Pass and Urea Compliance Testing
      Etiwanda Unit 3 Permit Application No. 261513*, Acurex Environmental, March 1994.

16.   *Emissions Source test Report: Permit Application No. R-249462, Huntington Beach Generating Station*, Acurex Environmental, March 1996.

17.   *Urea Permit Compliance Testing at El Segundo Generating Station Unit 4*, Carnot, September 1993.

18.   *California Fruit Produce, Fresno, Ca. Boiler Emissions Test 12-4-92.* Best Environmental, Inc., San Leandro, CA, December 17, 1992.

19.   *California Fruit Produce, Madera, Ca. Boiler Emissions Test 12-2-92.* Best Environmental Inc., San Leandro, CA, December 17, 1992.

20.   *Emission Testing at Zacky Farms Kewanee Boiler, Dinuba, California.* Steiner Environmental, Inc., Bakersfield, CA, July 1993.

21.   *Compliance Test Report Determination of NO_x emission rates From Boilers 3, 4, and 5. Harrison Radiator, Dayton, Ohio.* Hayden Environmental Group, Inc., Miamisburg, OH, March 20, 1990.

22.   *R. F. MacDonald Source Emissions Testing at Tomatek, Inc.* Ecoserve Environmental Services, Inc. Pittsburg, CA, October 1989.

23.   *Nitrogen Oxide Emission Tests Boilers Number 4 and 5. Whiteman Air Force Base.* Shell Engineering and Associates, Inc., August 20 and 21, 1990.

24.   *Source Emissions Survey of Firestone Synthetic Rubber & Latex company Boiler EB-114 Exhaust Stack, Orange, Texas.* METCO Environmental, Addison, TX, November 1990.

25.   *A Compliance Emission Test Report Determination of Nitrogen Oxides. Dual-Fuel Generating Units Nos. 1 and 2.* Greiner, Incorporated, Grand Rapids, MI, September 2, 1993.

26.   *Texaco Refining & Marketing, Inc. P. O. Box 1476, Bakersfield, California. Boilers A and B. Annual Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, June 19, 1992.

27.   *Source Emission Test for NO_x, CO, and ROC From Conventional Steam Boiler at Thomas Plant, Building 373, Naval Construction Battalion Center, Port Hueneme, California.* Naval Energy and Environmental Support Activity, October 1990.

28.   *Chevron U.S.A., Inc. Section 26C Steam Plant Steam Generator # 50-6 and 50-7. Initial Compliance Test.* Genesis Environmental Services Company, Bakersfield, CA, June 11, 1991.

29.   *Source Test for Measurement of Oxides of Nitrogen, Carbon Monoxide and VOC from Boiler Exhaust at Candlewick Yarns, Lemoore, California.* Pacific Environmental Services, Inc., Baldwin Park, CA, April 21, 1993.

30.   *Compliance Test for NO_x Siemens Energy and Automation Natural Gas Fired Boiler #2.* K&B Design, Inc., August 26, 1994.

31. *Source Test Report Gibson 7028-01, Gibson Oil and Refining Company, Bakersfield, California.* Brown and Caldwell, Pleasant Hill, CA, September 11, 1992.

32. *Source Test Report Gibson Oil and Refining Company, Inc.* Bakersfield, California. Brown and Caldwell, Emeryville, CA, May 14-17, 1990.

33. *Compliance Test Report: Determination of Nitrogen Oxide Emissions, Annapolis Hospital Westland Center Boilers #1, 2, and 3, Oakwood Hospital, Westland Michigan.* WW Engineering & Science, Grand Rapids, MI, November 1993.

34. *Report on Compliance Testing for General Motors Corporation, Fort Wayne Assembly Plant, Roanoke, Indiana,* Clean Air Engineering,

35. *Stella Cheese. P. O. Box 1379, Tulare, California. Superior Mohawk Boiler. Initial Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, July 30, 1993.

36. *Crystal Geyser Water Company. 1233 East California Avenue. Bakersfield, California. Boiler #1 & 2, Initial Compliance Test.* Steiner Environmental, Inc., Bakersfield, CA, February 26, 1993.

37. *Results of the Emissions Testing Services at Minnesota Corn Processors. Marshall Minnesota. December 20-21, 1994.* Nova Environmental Services, Inc., Chaska, MN, January 31, 1995.

38. *Results of the July 27, 1994 Air Emission Compliance Testing of the No. 10 Boiler at the Virginia Public Utilities Plant in Virginia, Minnesota.* Interpoll Laboratories, Inc., Circle Pines, MN, August 17, 1994.

39. *Los Gatos Tomato Products Compliance Emissions Testing.* Best Environmental, Inc., Hayward, CA, April 1991.

40. *Gallo Winery Fresno Plant Boilers # 1, 2, 3, & 4 Emissions Compliance Testing.* Best Environmental, Inc., San Leandro, CA, May 1992.

41. *Gas-Fired Boiler and Turbine Air Toxics Summary Report.* Prepared by Carnot Technical Services, Tustin, CA, For the Gas Research Institute and The Electric Power Research Institute, August 1996.

42. NO_x Emission Reporting for Utility Boilers for 3rd Quarter 1996. Acid Rain Division, U.S. EPA.

43. *Compliance Particulate Matter Source Emissions Measurement Program: Nebraska Package Boiler, Kimberly-Clark Corporation, Neenah, WI.* Geraghty & Miller, Inc., July 1994.

44. *Results of the September 14 and 15, 1994 Air Emission Compliance Tests on the No. 11 Boiler at the Appleton Paper Plant in Combined Locks, WI.* Interpoll Laboratories Inc., October 1994.

3.0   AP-42 Section Development

3.1   Revisions to Section Narrative

The technical discussion in AP-42 Section 1.4 did not need major revisions because no significant technological changes in this source category were identified since the last publication. Some of the discussion on NO_x and PM formation was revised to better describe emissions from this source category.

3.2   Pollutant Emission Factor Development

3.2.1   Database Design

The emission data assembled for the development of natural gas combustion emission factors were stored in a database except for the data received from ARD. A database approach was chosen to easily access and manipulate the large amount of data collected for this section and to facilitate data transfer within other concurrent projects at EPA. The design of this database was accomplished in conjunction with the Industrial Combustion Coordinated Rulemaking (ICCR) effort ongoing within the Emission Standards Division (ESD). Data entered under either of these projects were easily transferred between databases. Furthermore, the common design of the database will allow for future additions to the database and simple recalculation of emission factors.

Within the database, data were stored in two tables to reduce repetitive entry of data. These tables, and the data fields associated with each table are as follows:

Facilities Table

☐   Facility name
☐   Location
☐   Testing Company
☐   Date of Test
☐   Boiler Manufacturer
☐   Boiler Type (wall-fired, tangential-fired, etc.)
☐   Air Supply (forced draft, induced draft, balanced draft etc.)
☐   Capacity (MW)
☐   Load (percent of capacity)
☐   Fuel Type
☐   Fuel Higher Heating Value
☐   Heat Input (MMBtu/hr)
☐   Post-combustion Emission Controls
☐   Application (electrical generation, process steam, etc.)

Test Data Table

☐   Pollutant
☐   Test Method
☐   Pollutant Concentration (as reported)
☐   Detection Limit

- Exhaust Oxygen Percentage
- Data Rating
- Fuel Exhaust Factor (F-Factor)
- Exhaust Flow Rate
- Fuel Flow Rate
- Exhaust Moisture Fraction
- Molecular Weight of Pollutant

The database was programmed to merge the data in the two tables and calculate emission factors for the available pollutants in units of pounds of pollutant per million standard cubic feet of fuel burned. To ensure consistent calculation of emission factors, the database was programmed to use the emission concentration data and process data taken during the testing period to calculate the emission factors. Emission factors provided in test reports were not used. The EPA concluded that this method of calculation would provide the highest quality emission factors. This method of calculating emission factors was chosen because different methods of calculation emission factors were used in some of the references and in some cases, the method of calculating emission factors was not given. Equations used to calculate emission factors for this section were dependent on the pollutant concentration units.

The following equations were used to convert concentration data to the selected emission factors used in this section.

For concentration in parts per million by volume - dry (ppmvd), the following equation was used:

$$EF_{scf} = \frac{(C_{ppmvd} \times F \times 1,020 \times MW)}{(10^6 \times 385.5)} \times temperature\ correction \times oxygen\ correction$$

For concentration in parts per million by volume - wet (ppmvw), the following equation was used:

$$EF_{scf} = \frac{(C_{ppmvw} \times F \times 1,020 \times MW)}{(10^6 \times 385.5) \times (1 \times W_c)} \times temperature\ correction \times oxygen\ correction$$

For concentration in micrograms per dry standard cubic feet, the following equation was used:

$$EF_{scf} = \frac{(C_{\mu gf} \times F \times 1,020)}{(10^6 \times 453.6)} \times oxygen\ correction$$

For concentration in parts per billion by volume - dry, the following equation was used:

$$EF_{scf} = \frac{(C_{ppbvd} \cdot F \cdot 1,020 \cdot MW)}{(10^9 \cdot 385.5)} \cdot \text{temperature correction} \cdot \text{oxygen correction}$$

For concentration in volume percent, the following equation was used:

$$EF_{scf} = \frac{(C_{\%} \cdot F \cdot 1,020 \cdot MW)}{(100 \cdot 385.5)} \cdot \text{temperature correction} \cdot \text{oxygen correction}$$

For concentration in nanograms per dry standard cubic feet, the following equation was used:

$$EF_{scf} = \frac{(C_{ngf} \cdot F \cdot 1,020)}{(10^9 \cdot 453.6)} \cdot \text{oxygen correction}$$

For concentration in grains/dscf, the following equation was used:

$$EF_{scf} = (C_{grf} \cdot F \cdot 1,020 \cdot 1.43 \cdot 10^{-4}) \cdot \text{oxygen correction}$$

For concentration in micrograms per dry standard cubic meter, the following equation was used:

$$EF_{scf} = \frac{(C_{\mu gm} \cdot F \cdot 1,020)}{(10^6 \cdot 453.6 \cdot 35.31)} \cdot \text{oxygen correction}$$

Where:

Ef_{scf}	=	Emission factor (pounds per million standard cubic feet of fuel input)
C_{ppmvd}	=	Concentration (parts per million by volume, dry)
C_{ppmvw}	=	Concentration (parts per million by volume, wet)
$C_{\mu gf}$	=	Concentration (micrograms per dry standard cubic foot)
C_{ppbvd}	=	Concentration (parts per billion by volume, dry)
$C_{\%}$	=	Concentration (percent by volume)
C_{ngf}	=	Concentration (nanograms per dry standard cubic foot)
C_{grf}	=	Concentration (grains per dry standard cubic foot)
$C_{\mu gm}$	=	Concentration (micrograms per dry standard cubic meter)
F	=	F-Factor (dry standard cubic feet per million Btu)
MW	=	Molecular weight (pounds per pound-mole)
T_{std}	=	Reference temperature of F-Factor

$\%O_2$	=	Percent of oxygen in exhaust, by volume
1,020	=	Natural gas heating value (MMBtu per 10^6 scf)
385.5	=	Volume occupied by 1 lb-mole of gas at 68°F (standard cubic feet per lb-mole)
60	=	Conversion factor (minutes per hour)
W_c	=	Water volume fraction in exhaust
453.6	=	Conversion factor (grams per pound)
$1.43*10^{-4}$	=	Conversion factor (pounds per grain)
35.31	=	Conversion factor (dry standard cubic feet per dry standard cubic meter)

$$\text{Temperature correction for F Factor (to 68°F)} = \left(\frac{528°R}{460°R_t + T_{std} °F} \right)$$

$$\text{Oxygen correction (to 0\% } O_2) = \left(\frac{20.9}{20.9 - \%O_2} \right)$$

Detection Limits

Test results from several tests of trace organic and metallic compounds reported concentrations below the method detection limits. If a detection limit was provided in the test report, EPA used that information in the development of AP-42 emission factors. To effectively use this data, two methods were employed. For cases where a portion of the test data for a specific pollutant were below the method detection limit but other test data report detection of that compound, then one-half of the detection limit was averaged with the detected concentrations to calculate of the emission factor for that pollutant. In cases where all of the test data for a specific pollutant reported concentrations below the method detection limit, the lowest detection limit was reported for the emission factor for that pollutant, and that factor noted as a detection limit. If an emission factor for an individual boiler was developed from a detection limit and the resulting emission factor was higher than the emission factors generated from detected concentrations, the emission factor based on a detection limit was removed from the average. The goal of this decision was to prevent an unusually high detection limit from artificially increasing an average emission factor. These methods for addressing detection level issues were provided in the Procedures For Preparing Emission Factor Documents.[1]

Calculation of Average Emission Factors

To provide average emission factors for these sources, the arithmatic average of the emission factors from all tests on a specific source type was calculated in the database. For tests that consisted of multiple runs, the arithmetic average of the runs was used to develop the emission factor of that test. Individual tests were given equal weight in the calculation of average emission factors for each boiler group. In the case of NO_x data received from ARD, the quarterly average from each boiler was treated like an individual test.

Presentation of Data

Due to the size of the database, a printout of all the test data used to generate the boiler emission factors in Section 1.4 is not presented. The NO_x data provided by the Acid Rain Division is provided in Appendix A. For the remaining data that was stored in the database, EPA is providing an electronic copy of the database on the Technology Transfer Network (TTN). This decision has resulted in a substantial decrease in paper needed for this background information document and will provide users with a more detailed background data set for this section. Providing the database to the public will allow anyone to use or augment the database for their individual needs, providing a substantial building block for anyone interested in compiling an extensive database on natural gas-fired combustion sources. An electronic copy of the database in Microsoft Access® format, can be downloaded from the TTN at http://www.epa.gov/tnn/chief/. In this website, go to AP-42 and follow the main menu options to locate and download the database file.

3.2.2   Results of Data Analysis

3.2.2.1 Source Category Selection and Data Review

An important step in emission factor development is to determine which emission sources are similar enough to be grouped together and represented by a single emission factor. This is accomplished by investigating what parameters influence emissions and should be used to establish distinct groups within the natural gas combustion category. The emission factors for each test contained in the database were analyzed to determine appropriate groupings.

NO_x Emission Factors

Based on the analysis of available NO_x data, this category was separated into four general groups: large wall-fired boilers with a heat input greater than 100 MMBtu/hr, small boilers with a heat input less than 100 MMBtu/hr, tangential-fired boilers, and residential furnaces. These groups were further separated into the following subcategories:

    ☐   Large Wall-Fired Boilers (>100 MMBtu/hr)

            -      Uncontrolled (pre-NSPS)
            -      Uncontrolled (post-NSPS)
            -      Controlled-Low-NO_x burner
            -      Controlled-Flue Gas Recirculation (FGR)

    ☐   Small Boilers (<100 MMBtu/hr)

            -      Uncontrolled
            -      Controlled-Low-NO_x burner
             -      Controlled-Low-NO_x burner/FGR

    ☐   Tangential-Fired Boilers

            -      Uncontrolled
             -      Controlled-FGR

☐   Residential Furnaces

The designation of pre- and post-NSPS refers to boilers that are subject to 40 CFR 60 Subparts D and Db. Post-NSPS units are boilers with greater than 250 MMBtu/hr of heat input that commenced construction, modification, or reconstruction after August 17, 1971, and units with heat input capacities between 100 and 250 MMBtu/hr that commenced construction, modification, or reconstruction after June 19, 1984. Analysis of the NO_x data showed that uncontrolled wall-fired boilers subject to the NSPS have considerably lower NO_x emissions that those not subject to the NSPS. Such a distinction was not seen in the data for the tangential boilers and therefore they were not further subcategorized.

The NO_x emission factors for the following categories were developed from data received from ARD: large wall-fired uncontrolled, large wall-fired controlled-low NO_x burners, and tangential-fired uncontrolled. The ARD data were determined to be more representative of these categories than NO_x data taken from compliance and source tests. The ARD data were from all operating utility boilers in the U.S. and averaged continuously over a three-month period. Since most of the data stored in the database were from short-term compliance and source tests, and from a much smaller population of boilers, the ARD data were used for categories where they were available. The NO_x emission factors for the remaining categories, where ARD data were unavailable, were developed from data stored in the database.

The NO_x emission factor for residential furnaces is based on test data from 41 sources.[2-3] Since no new data for NO_x from residential furnaces were obtained during this revision, this factor remains unchanged from the previous version of Section 1.4.

N$_2$O Emission Factors

The emission factors for N_2O from large wall-fired boilers is based on test data from five source tests conducted at three separate locations.[4-5] The N_2O factor for the large wall-fired boilers with low-NO_x burners is based on two source tests.[4-5] Since no new data for N_2O were obtained during this revision, these factors remain unchanged from the previous version of Section 1.4.

CO Emission Factors

Emission factors for CO were not grouped as extensively as the NO_x emission factors. For the wall-fired boiler groups, no clear correlation was observed between boiler type or size and CO emission levels. CO emission factors for the wall-fired boilers showed wide scatter and average emission factors developed for the distinct grouping were not consistent with expected values. The EPA believes that boiler operation plays a more critical role in determining CO emissions than the boiler type. Therefore, all CO data for wall-fired boilers were averaged to provide a single CO emission factor. For the tangential-fired boilers, CO emission factors showed less scatter and were strongly dependent on boiler type. Therefore, CO emission factors for tangential-fired boilers were grouped under the uncontrolled and controlled-flue gas recirculation categories.

The CO emission factor from residential furnaces is based on test data from 41 sources.[2-3] Since no new data for CO from residential furnaces were obtained during this revision, this factor remains unchanged from the previous version of Section 1.4.

Organic Compound Emission Factors

Similar to CO emission factors from wall-fired boilers, organic compound emission factors (TOC, VOC, methane, formaldehyde, etc.) showed wide scatter and no correlation was observed with boiler type or size. The EPA believes that the randomness of the organic compound emission factors from natural gas combustion sources is driven more by individual source operation than source type. Therefore, the organic compound emission factors for natural gas combustion sources were averaged across the entire source category to provide single factors for all sources covered by AP-42 Section 1.4.

3.2.2.2 Data Not Included in the Database

Several of the emission factors presented in AP-42 Section 1.4 are not calculated via a simple averaging procedure in the database. These emission factors include TOC, VOC, PM, CO_2, SO_2, and controlled emission factors. The next several sections will discuss the development of these emission factors.

VOC and TOC Emission Factors

The VOC emission factor for this source category was calculated to correspond with EPA's definition that VOC comprises total organic compounds excluding methane, ethane, and several chlorinated and fluorinated compounds.[1] Since VOCs cannot be measured directly, VOC emission factors must be calculated from other organic measurements. Data on hydrocarbon emissions collected for the revision of AP-42 Section 1.4 included as total hydrocarbons (THC) and non-methane hydrocarbons (NMHC). Based on an evaluation of the quality and quantity of data available on hydrocarbons, EPA determined that the NMHC data was the most representative for this source category. Given the NMHC as the basis for calculating the VOC emission factor, the ethane emission factor was subtracted and the formaldehyde emission factor added to the NMHC emission factor to provide an estimate of the VOC emission factor. This calculation is shown below. The TOC emission factor was estimated by adding the methane and formaldehyde emission factors to the NMHC emission factor. This calculation is shown below. The data used in these calculations can be found in Table 3.4-1.

$$VOC = NMHC + Formaldehyde - Ethane$$

$$= 8.5 + 0.07 - 3.1$$

$$= 5.5 \ (lb/10^6 \ scf)$$

$$TOC = NMHC + Formaldehyde + Methane$$

$$= 8.5 + 0.07 + 2.3$$

$$= 10.9 \ (lb/10^6 \ scf)$$

PM Emission Factors

For a limited number of tests, PM measurements were conducted. These PM measurements included both condensable and filterable PM. As with the organic compounds emitted from natural gas combustion sources, no correlation between combustion source type and PM emission levels could be established. Therefore, the PM emission factors presented in AP-42 Section 1.4 are intended to represent all natural gas combustion sources. To provide a total PM emission factor, the average condensible and filterable PM fractions were added together. This calculation is shown below. The EPA has assumed that all condensable and filterable PM resulting from natural gas combustion is less that 1 micrometer ($\square$m) in diameter. Therefore, the total PM emission factor also provided an estimate of PM_{10}, $PM_{2.5}$, and $PM_{1.0}$ emissions from natural gas combustion sources. The EPA believes that these assumptions for PM size are valid since natural gas does not contain ash and the nucleation of PM from combustion products ill not yield particles larger than 1 $\square$m.

$$PM\ (Total) = PM\ (Condensable) + PM\ (Filterable)\ \square\ PM_{10}\ \square\ PM_{2.5}\ \square\ PM_{1.0}$$

$$= 5.7 + 1.9$$

$$= 7.6\ (lb/10^6\ scf)$$

CO_2 and SO_2

As outlined in the Procedures for Preparing Emission Factor Documents,[1] emission factors for CO_2 were calculated by mass balance. This approach was also taken for calculating SO_2. Since the carbon and sulfur content in pipeline-quality natural gas is fairly consistent, EPA believes that this is the best method for calculating CO_2 and SO_2 emission factors. For CO_2, it was assumed that approximately 100 percent of the fuel carbon was converted to CO_2. For SO_2, a 100 percent conversion of fuel sulfur was assumed. The CO_2 emission factor was based on a carbon weight percent in natural gas of 76 percent and the SO_2 emission factor was based on a sulfur content in natural gas of 2,000 grains per million standard cubic feet.

Selective Non-catalytic Reduction (SNCR) Controlled Emission Factors

Several of the data sources provided emissions data for sources operating with SNCR control. To evaluate SNCR control efficiency, only tests where NO_x measurements were taken upstream and downstream of the ammonia or urea injection area were considered. This method was chosen to evaluate SNCR performance while avoiding the effects of boiler performance, with respect to NO_x emissions. To estimate SNCR performance, NO_x control efficiency was based on tests conducted upstream and downstream of the control device. Thirty-three sets of upstream and downstream tests on SNCR performance were evaluated. The SNCR performance data for wall-fired boilers are presented in Table 3.2-1 and SNCR performance data for tangential-fired boilers are presented in Table 3.2-2. The average NO_x reduction efficiency achieved by SNCR control on wall-fired and tangential-fired units was 24 percent and 13 percent, respectively. These reduction efficiencies were also put in the footnotes to the tables presented in Section 1.4 so these reduction efficiencies could be applied to the NO_x emission factor if necessary.

3.3 Emission Factor Quality Rating System

The quality of the emission factors developed from analysis of the test data was rated using the following general criteria:

A--Excellent: Developed only from A-rated test data taken from many randomly chosen facilities in the industry population. The source category is specific enough that variability within the source category population may be minimized.

B--Above average: Developed only from A-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industries. The source category is specific enough that variability within the source category population may be minimized.

C--Average: Developed only from A- and B-rated test data from a reasonable number of facilities. Although no specific bias is evident, it is not clear if the facilities tested represent a random sample of the industry. The source category is specific enough that variability within the source category population may be minimized.

D--Below average: The emission factor was developed only from A- and B-rated test data from a small number of facilities, and there is reason to suspect that these facilities do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of the emission factor are always noted in the emission factor table.

Table 3.2-1. SNCR TEST RESULTS FOR WALL-FIRED BOILERS (NO_x)

Database I.D.	Uncontrolled Emission Factor ($1b/10^6$ scf)	Controlled Emission Factor ($1b/10^6$ scf)	Percent Reduction (%)
16.1/16.2	1.32E+02	1.17E+02	11
16.3/16.4	8.14E+01	6.31E+01	23
16.5/16.6	5.57E+01	4.53E+01	19
23.1/23.2	1.12E+02	9.64E+01	14
23.3/23.4	8.20E+01	5.96E+01	27
23.5/23.6	5.24E+01	4.10E+01	22
15.1/15.2	1.78E+02	1.29E+02	27
15.3/15.6	1.08E+02	9.25E+01	14
15.8/15.7	1.79E+02	1.51E+02	16
18.2/18.1	1.97E+02	1.30E+02	34
18.4/18.3	1.03E+02	7.76E+01	25
18.6/18.5	5.29E+01	3.08E+01	42
18.7/18.8	1.76E+02	1.25E+02	29
18.9/18.10	1.01E+02	7.79E+01	23
18.12/18.11	7.91E+01	4.81E+01	39
		Average =	24

Table 3.2-2. SNCR TEST RESULTS FOR TANGENTIAL-FIRED BOILERS (NO$_x$)

Database I.D.	Uncontrolled Emission Factor (1b/10^6 scf)	Controlled Emission Factor (1b/10^6 scf)	Percent Reduction (%)
20.2/20.1	5.45E+01	4.70E+01	14
20.4/20.3	8.21E+01	6.87E+01	16
20.6/20.5	9.08E+01	8.12E+01	11
21.1/21.2	6.63E+01	5.93E+01	10
21.4/21.3	9.36E+01	7.77E+01	17
21.6/21.5	1.05E+02	9.42E+01	10
22.2/22.3	6.83E+01	5.82E+01	15
22.5/22.6	4.08E+01	3.53E+01	13
17.1/17.2	6.70E+01	6.47E+01	3
17.10/17.9	7.39E+01	5.97E+01	19
17.12/17.11	8.70E+01	7.34E+01	16
17.4/17.3	5.42E+01	4.79E+01	12
17.6/17.5	7.16E+01	4.43E+01	38
17.8/17.7	8.36E+01	7.64E+01	9
19.2/19.3	8.38E+01	7.40E+01	12
19.6/19.8	4.35E+01	4.10E+01	6
19.7/19.8	4.35E+01	4.10E+01	6
19.10/19.9	4.79E+01	4.38E+01	9
		Average =	13

E--Poor: The emission factor was developed from C- and D-rated test data, and there is reason to suspect that the facilities tested do not represent a random sample of the industry. There also may be evidence of variability within the source category population. Limitations on the use of these factors are always noted, in the emission factor table.

The above criteria for emission factor ratings are defined in and OAQPS document which provided guidance for preparing emission factor documents. The use of these criteria is somewhat subjective and depends to an extent upon the individual reviewer. As these criteria were applied to the emission factors, the term "number of facilities" was interpreted to mean "number of different boilers". This criteria prevented emission factors generated from multiple tests on a single boiler from receiving higher emission factor ratings.

Emission factors for this section were rated in the following manner:

A-Rated   Emission factor average based on results of A-rated data from 20 or more different boilers, or from approved mass balance calculations.

B-Rated   Emission factor average based on results of A-rated data from 10 to 19 different boilers.

C-Rated   Emission factor average based on results of A-rated data from five to

nine different boilers.

D-Rated   Emission factor average based on results of A-rated data from three to four different boilers.

E-Rated   Emission factor based on less than three A- or B-rated source tests.

In several cases for the revision of AP-42 Section 1.4, the data did not show a strong enough correlation to boiler type, boiler size, or combustion control to justify the grouping of data by these parameters. Where data were averaged across these parameters, the resulting emission factors were rated by the above criteria but subsequently lowered one rating. The decision was made to lower the emission factor rating in these cases to reflect the lack of certainty in the resulting emission factor.

3.4   Emission Factors

The emission factors for the sources covered in Section 1.4 of the AP-42 document are presented in Table 3.4-1. This table provides the number of source tests used in calculating the various emission factors as well as the relative standard deviation associated with each emission factor. This additional information is intended to provide greater insight to the reader about the background of each emission factor. For further detail on each emission factor, the database used to generate most of these factors (except for NO_x emission factors generated from ARD data) is provided on the TTN (See Section 3.2.1 of this document for more details on the database). For NO_x emission factors generated from data provided by the Acid Rain Division, the supporting data is provided in Appendix A.

3.5   Peer Review Process

Part of the development processes of an AP-42 section includes review by a peer group. This group include individuals from EPA, industry, and environmental organizations. In the peer review process, EPA gains an extra level of confidence in the final version of a section. Comments received on the draft version of a section are reviewed to determine if they warrant any changes to the draft version of the section before it becomes final. Appendix B presents the substantial comments received on the draft AP-42 Section 1.4 and EPA's responses to those comments.

3.6   References for Section 3

1.   Procedures for Preparing Emission Factor Documents, EPA-454/R-95-015, Office of Air Quality Planning and Standards, U.S. EPA, Research Triangle Park, North Carolina 27711, September 1997.

2.   Muhlbaier, J.L. "Particulate and Gaseous Emissions from Natural Gas Furnaces and Water Heaters," Journal of the Air Pollution Control Association, December 1981.

3.   Evaluation of the Pollutant Emissions from Gas-Fired Forced Air Furnaces: Research Report No. 1503, American Gas Association Laboratories, Cleveland, OH. May 1975.

4.   Nelson, L.P., L.M. Russell, J. J. Watson. "Global Combustion Sources of Nitrous Oxide Emissions," Research Project 2333-4 Interim Report. Radian Corporation, Sacramento, California. 1991.

5.   Peer, R.L., E.P. Epner, R.S. Billings. "Characterization of Nitrous Oxide Emission Sources,"
      Prepared for U.S. EPA Contract 68-D1-0031. Radian Corporation, Research Triangle Park,
      North Carolina. 1995.

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR AP-42 SECTION 1.4

Pollutant	Number of Tests	Emission Factor (lb/10^6 scf)	Relative Standard Deviation (%)
2-Methylnaphthalene	4	2.4E-5	72.77%
3-Methylchloranthrene	1	<1.8E-6	
7,12-Dimethylbenz(a)anthracene	1	<1.6E-5	
Acenaphthene	1	<1.8E-6	
Acenaphthylene	1	<1.8E-6	
Anthracene	1	<2.4E-6	
Arsenic	2	2.0E-4	22.36%
Barium	3	4.4E-3	38.85%
Benz(a)anthracene	1	<1.8E-6	
Benzene	17	2.1E-3	172.00%
Benzo(a)pyrene	1	<1.2E-6	
Benzo(b)fluoranthene	1	<1.8E-6	
Benzo(g,h,i)perylene	1	<1.2E-6	
Benzo(k)fluoranthene	1	<1.8E-6	
Beryllium	1	<1.2E-5	
Butane	1	2.1	
Cadmium	3	1.1E-3	166.72%
Chromium	5	1.4E-3	55.69%
Chrysene	1	<1.8E-6	
CO (Wall-Fired)	49	84	124.00%
CO (Tangential-Uncontrolled)	17	24	179.00%
CO (Tangential-FGR)	7	98	57.00%
Cobalt	2	8.4E-5	63.59%
Copper	4	8.5E-4	49.36%
Dibenzo(a,h)anthracene	1	<1.2E-6	
Dichlorobenzene	1	1.2E-3	
Ethane	4	3.1	43.77%
Fluoranthene	1	3.0E-6	
Fluorene	2	2.8E-6	14.02%
Formaldehyde	22	8.1E-2	194.00%
Hexane	2	1.8	95.61%
Indeno(1,2,3-cd)pyrene	1	<1.8E-6	
Lead	4	4.6E-4	77.61%
Manganese	2	3.8E-4	2.53%
Mercury	2	2.6E-4	43.50%
Methane	42	2.3	118.83%
Molybdenum	2	1.1E-3	64.41%
Naphthalene	2	6.1E-4	85.19%

Table 3.4-1. SUMMARY OF EMISSION FACTORS FOR AP-42 SECTION 1.4 (Continued)

Pollutant	Number of Tests	Emission Factor (lb/10^6 scf)	Relative Standard Deviation (%)
Nickel	5	2.1E-3	72.26%
NMHC	48	8.5	150.26%
NOx (Small-Unc.)	18	104	51.00%
NOx (Small-Low NOx)	5	50	54.00%
NOx (Small-Low NOx/FGR)	15	32	18%
NOx (Large Wall-Fired-Low NOx)	5	136	37.00%
NOx (Large Wall-Fired-FGR)	4	101	25.00%
NOx (Large Wall-Fired Unc. Pre-NSPS)	108	275	93.00%
NOx (Large Wall-Fired Unc. Post-NSPS)	13	192	36.00%
NOx (Tangential-Unc.)	62	167	37.00%
NOx (Tangential-FGR)	8	76	64.00%
Pentane	1	2.6	
Phenanthrene	4	1.7E-5	63.82%
PM, Condensible	4	5.7	69.79%
PM, Filterable	21	1.9	111.47%
Propane	1	1.6	
Pyrene	1	5.0E-6	
Selenium	1	<2.4E-5	
Toluene	11	3.4E-3	93.00%
Vanadium	3	2.3E-3	71.77%
Zinc	1	2.9E-2	

4.0   AP-42 Section 1.4

APPENDIX A

Acid Rain Division Data

UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
3892	City of Coffeyville Mun. Lght & Pow	Coffeyville	KS	283	0.155	158
814	ENTERGY	Harvey Couch	AR	129	0.282	288
44372	TU Electric	Handley	TX	518	0.403	411
19804	City of Vero Beach	Vero Beach Municipal	FL	337	0.124	126
1167	Baltimore Gas and Electric Company	Riverside	MD	308	0.338	345
22500	Western Resources, Inc.	Murray Gill	KS	251	0.211	215
15474	Central and South West Services	Southwestern	OK	149	0.278	284
14354	Illinois Power	Gadsby	UT	438	0.104	106
814	ENTERGY	Lake Catherine	AR	506	0.24	245
44372	TU Electric	Parkdale	TX	509	0.339	346
44372	TU Electric	Lake Creek	TX	519	0.282	288
17718	Southwestern Public Service Co.	Plant X	TX	348	0.347	354
814	ENTERGY	Harvey Couch	AR	502	0.1	102
16572	Salt River Project Ag. Imp. & Power	Kyrene	AZ	391	0.28	286
14534	City of Pasadena, Water & Power Dep	Broadway	CA	145	0.097	99
22500	Western Resources, Inc.	Murray Gill	KS	381	0.165	168
15474	Central and South West Services	Southwestern	OK	149	0.257	262
44372	TU Electric	Eagle Mountain	TX	736	0.509	519
3278	Central and South West Services	Lon C Hill	TX	447	0.254	259
44372	TU Electric	Morgan Creek	TX	449	0.412	420
14063	Oklahoma Gas & Electric Co.	Mustang	OK	726	0.302	308
44372	TU Electric	Parkdale	TX	620	0.41	418
22500	Western Resources, Inc.	Murray Gill	KS	428	0.224	228
14063	Oklahoma Gas & Electric Co.	Muskogee	OK	826	0.303	309
3278	Central and South West Services	Lon C Hill	TX	433	0.222	226
17698	Central and South West Services	Knox Lee	TX	436	0.324	330
44372	TU Electric	Mountain Creek	TX	704	0.237	242
44372	TU Electric	Eagle Mountain	TX	1051	0.29	296

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UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
16572	Salt River Project Ag. Imp. & Power	Agua Fria	AZ	742	0.25	255
16572	Salt River Project Ag. Imp. & Power	Agua Fria	AZ	752	0.25	255
44372	TU Electric	Parkdale	TX	648	0.369	376
6958	City of Garland	Ray Olinger	TX	630	0.187	191
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	842	0.189	193
44372	TU Electric	Stryker Creek	TX	1050	0.36	367
44372	TU Electric	Mountain Creek	TX	779	0.5	510
44372	TU Electric	Permian Basin	TX	185	0.26	265
22500	Western Resources, Inc.	Murray Gill	KS	315	0.263	268
14063	Oklahoma Gas & Electric Co.	Mustang	OK	396	0.546	557
44372	TU Electric	Lake Creek	TX	1280	0.28	286
44372	TU Electric	Morgan Creek	TX	1233	0.29	296
44372	TU Electric	North Lake	TX	770	0.173	176
20404	Central and South West Services	Paint Creek	TX	169	0.137	140
44372	TU Electric	Graham	TX	1579	0.29	296
17609	Southern California Edison Co.	Cool Water	CA	534	0.098	100
22500	Western Resources, Inc.	Gordon Evans	KS	546	0.225	230
3265	Central Louisiana Electric Co., Inc	Coughlin	LA	488	0.321	327
13407	Nevada Power Company	Clark	NV	361	0.262	267
44372	TU Electric	North Lake	TX	1051	0.24	245
44372	TU Electric	Valley	TX	1114	0.24	245
20404	Central and South West Services	Oak Creek	TX	548	0.209	213
6616	Fort Pierce Utilities Auth	Henry D King	FL	189	0.198	202
20391	WestPlains Energy	Arthur Mullergren	KS	378	0.12	122
20391	WestPlains Energy	Cimarron River	KS	394	0.219	223
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	1275	0.137	140
16604	City Public Service	W B Tuttle	TX	851	0.131	134
6958	City of Garland	C E Newman	TX	86	0.434	443
2172	Brazos Electric Power Cooperative,	North Texas	TX	245	0.299	305

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UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
44372	TU Electric	Handley	TX	2383	0.281	287
7294	City of Glendale, Public Service De	Grayson	CA	161	0.06	61
17609	Southern California Edison Co.	Cool Water	CA	709	0.106	108
13407	Nevada Power Company	Sunrise	NV	379	0.354	361
20447	Western Farmers Electric	Mooreland	OK	252	0.323	329
44372	TU Electric	North Lake	TX	2025	0.28	286
8901	Houston Lighting & Power Company	Webster	TX	1823	0.237	242
11269	Lower Colorado River Authority	Sim Gideon	TX	664	0.202	206
18445	Electric Operations	S O Purdom	FL	272	0.202	206
3265	Central Louisiana Electric Co., Inc	Coughlin	LA	797	0.301	307
1015	City of Austin Electric Utility Dpt	Holly Street	TX	810	0.157	160
5063	City of Denton	Spencer	TX	354	0.334	341
44372	TU Electric	Morgan Creek	TX	3671	0.591	603
10620	City of Lake Worth	Tom G Smith	FL	158	0.234	239
22500	Western Resources, Inc.	Gordon Evans	KS	1514	0.409	417
15474	Central and South West Services	Southwestern	OK	576	0.372	379
44372	TU Electric	Valley	TX	3312	0.25	255
16463	Ruston Utilities System	Ruston	LA	42	0.182	186
20447	Western Farmers Electric	Mooreland	OK	648	0.213	217
2172	Brazos Electric Power Cooperative,	R W Miller	TX	499	0.175	179
11269	Lower Colorado River Authority	Sim Gideon	TX	659	0.189	193
20391	WestPlains Energy	Judson Large	KS	600	0.159	162
7634	City of Greenville	Powerlane Plant	TX	31	0.136	139
44372	TU Electric	Tradinghouse	TX	3111	0.335	342
44372	TU Electric	Graham	TX	2161	0.42	428
2442	Bryan Utilities	Bryan	TX	139	0.211	215
20404	Central and South West Services	Rio Pecos	TX	912	0.384	392
814	ENTERGY	Lake Catherine	AR	2469	0.22	224
20813	City of Winfield	East 12Th St	KS	194	0.261	266

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UNCONTROLLED NOx EMISSION DATA FOR LARGE PRE-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	454	0.323	329
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	486	0.303	309
17568	South Missisippi Elec. Power Assoc.	Moselle	MS	434	0.28	286
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1806	0.167	170
44372	TU Electric	Lake Hubbard	TX	2198	0.17	173
17698	Central and South West Services	Wilkes	TX	1759	0.299	305
18445	Electric Operations	Arvah B Hopkins	FL	433	0.239	244
2777	Cajun Electric Power Cooperative	Big Cajun 1	LA	925	0.437	446
3265	Central Louisiana Electric Co., Inc	Teche	LA	1758	0.22	224
44372	TU Electric	Eagle Mountain	TX	2021	0.17	173
44372	TU Electric	Valley	TX	2276	0.161	164
17698	Central and South West Services	Wilkes	TX	1653	0.263	268
20404	Central and South West Services	Paint Creek	TX	521	0.309	315
6909	Gainesville Regional Utilities	Deerhaven	FL	638	0.151	154
2777	Cajun Electric Power Cooperative	Big Cajun 1	LA	657	0.347	354
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1870	0.188	192
44372	TU Electric	Tradinghouse	TX	4972	0.441	450
2172	Brazos Electric Power Cooperative,	R W Miller	TX	993	0.36	367
5063	City of Denton	Spencer	TX	418	0.294	300
44372	TU Electric	Permian Basin	TX	3929	0.873	890
44372	TU Electric	Lake Hubbard	TX	2844	0.214	218
20404	Central and South West Services	Fort Phantom	TX	966	0.331	338

Pre-NSPS Average Nox (lb/MMscf) = 275
(lb/MMBtu) = 0.27

UNCONTROLLED NOX EMISSION DATA FOR LARGE POST-NSPS WALL-FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
20447	Western Farmers Electric	Mooreland	OK	721	0.224	228
14063	Oklahoma Gas & Electric Co.	Seminole	OK	1773	0.205	209
3278	Central and South West Services	La Palma	TX	1005	0.272	277
44372	TU Electric	Decordova	TX	5148	0.324	330
6616	Fort Pierce Utilities Auth	Henry D King	FL	291	0.121	123
9096	Lafayette Utilities System	Doc Bonin	LA	822	0.252	257
44372	TU Electric	Handley	TX	2629	0.15	153
6958	City of Garland	Ray Olinger	TX	1009	0.177	181
18445	Electric Operations	Arvah B Hopkins	FL	1510	0.187	191
7634	City of Greenville	Powerlane Plant	TX	162	0.097	99
44372	TU Electric	Handley	TX	2577	0.12	122
20404	Central and South West Services	Fort Phantom	TX	1189	0.122	124
5109	Detroit Edison Company	Greenwood	MI	2483	0.19	194

Post-NSPS Average NOx (lb/MMscf) =192

(lb/MMBtu) = 0.19

NOx EMISSION DATA FOR WALL-FIRED BOILERS WITH LOW NOx BURNERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	NOx rate-3Q (lb/MMBtu)	NOx rate-3Q (lb/MMscf)
2507	City of Burbank - Public Service De	Magnolia	CA	105	0.108	110
14534	City of Pasadena, Water & Power Dep	Broadway	CA	145	0.107	109
2507	City of Burbank - Public Service De	Olive	CA	147	0.082	84
3265	Central Louisiana Electric Co., Inc	Rodemacher	LA	1737	0.203	207
13998	Ohio Edison Company	Edgewater	OH	380	0.167	170

Average NOx (lb/MMscf) = 136

(lb/MMBtu) = 0.13

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UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
9726	GPU Generation Corporation	Gilbert	NJ	505	0.238	243
195	Alabama Power Company	Chickasaw	AL	256	0.168	171
12686	Mississippi Power Company	Sweatt	MS	344	0.335	342
3249	Central Hudson Gas & Electric Corp.	Danskammer	NY	205	0.08	82
14354	Illinois Power	Gadsby	UT	392	0.093	95
12686	Mississippi Power Company	Sweatt	MS	346	0.325	332
17718	Southwestern Public Service Co.	Plant X	TX	605	0.125	128
803	Arizona Public Service Company	Saguaro	AZ	720	0.335	342
6452	Florida Power & Light Company	Cutler	FL	518	0.083	85
3249	Central Hudson Gas & Electric Corp.	Danskammer	NY	381	0.102	104
803	Arizona Public Service Company	Saguaro	AZ	622	0.219	223
6452	Florida Power & Light Company	Cutler	FL	919	0.079	81
44372	TU Electric	Collin	TX	753	0.139	142
17718	Southwestern Public Service Co.	Plant X	TX	529	0.158	161
14354	Illinois Power	Gadsby	UT	624	0.08	82
17609	Southern California Edison Co.	San Bernardino	CA	395	0.1	102
17698	Central and South West Services	Lieberman	LA	471	0.15	153
12686	Mississippi Power Company	Jack Watson	MS	309	0.197	201
17718	Southwestern Public Service Co.	Cunningham	NM	502	0.225	230
24211	Tucson Electric Power Company	Irvington	AZ	363	0.147	150
17609	Southern California Edison Co.	San Bernardino	CA	393	0.103	105
803	Arizona Public Service Company	Yuma Axis	AZ	343	0.071	72
17698	Central and South West Services	Lieberman	LA	424	0.14	143
803	Arizona Public Service Company	Ocotillo	AZ	598	0.147	150
803	Arizona Public Service Company	Ocotillo	AZ	561	0.138	141
24211	Tucson Electric Power Company	Irvington	AZ	367	0.185	189
7806	Entergy Corporation	R S Nelson	LA	810	0.161	164
17698	Central and South West Services	Arsenal Hill	LA	505	0.134	137

UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
12686	Mississippi Power Company	Jack Watson	MS	307	0.149	152
1015	City of Austin Electric Utility Dpt	Holly Street	TX	512	0.102	104
8901	Houston Lighting & Power Company	T H Wharton	TX	954	0.157	160
24211	Tucson Electric Power Company	Irvington	AZ	443	0.202	206
12686	Mississippi Power Company	Jack Watson	MS	490	0.194	198
17718	Southwestern Public Service Co.	Nichols Station	TX	652	0.15	153
17698	Central and South West Services	Wilkes	TX	841	0.151	154
17718	Southwestern Public Service Co.	Plant X	TX	859	0.181	185
22500	Western Resources, Inc.	Hutchinson	KS	579	0.272	277
17718	Southwestern Public Service Co.	Cunningham	NM	1200	0.208	212
44372	TU Electric	Stryker Creek	TX	3615	0.16	163
16604	City Public Service	V H Braunig	TX	1216	0.162	165
17718	Southwestern Public Service Co.	Maddox	NM	883	0.154	157
6958	City of Garland	Ray Olinger	TX	332	0.12	122
44372	TU Electric	Mountain Creek	TX	3481	0.162	165
16604	City Public Service	V H Braunig	TX	1069	0.179	183
17718	Southwestern Public Service Co.	Nichols Station	TX	945	0.218	222
9096	Lafayette Utilities System	Doc Bonin	LA	427	0.141	144
14063	Oklahoma Gas & Electric Co.	Horseshoe Lake	OK	590	0.081	83
1015	City of Austin Electric Utility Dpt	Decker Creek	TX	1574	0.155	158
16604	City Public Service	V H Braunig	TX	1945	0.218	222
17718	Southwestern Public Service Co.	Jones Station	TX	1422	0.249	254
16604	City Public Service	O W Sommers	TX	2138	0.205	209
11269	Lower Colorado River Authority	Sim Gideon	TX	1603	0.174	177
8901	Houston Lighting & Power Company	Greens Bayou	TX	2094	0.113	115
16604	City Public Service	O W Sommers	TX	2525	0.153	156
16463	Ruston Utilities System	Ruston	LA	17	0.14	143
1015	City of Austin Electric Utility Dpt	Holly Street	TX	1151	0.178	182
17718	Southwestern Public Service Co.	Jones Station	TX	1368	0.245	250
11269	Lower Colorado River Authority	T C Ferguson	TX	2120	0.175	179

UNCONTROLLED NOx EMISSION DATA FOR TANGENTIAL FIRED BOILERS (CONTINUED)

util code	utility	plant	state	Average heat input (MMBtu/hr)	nox rate-3Q (lb/MMBtu)	nox rate-3Q (lb/MMscf)
1015	City of Austin Electric Utility Dpt	Decker Creek	TX	2504	0.113	115
16687	Savannah Electric and Power Co.	Riverside	GA	175	0.114	116
17718	Southwestern Public Service Co.	Moore County Station	TX	345	0.138	141
44372	TU Electric	Trinidad	TX	1550	0.204	208

Average (lb/MMscf) = 167
(lb/MMBtu) = 0.16

APPENDIX B

Reviewer Comments and EPA Responses

List of Addresseses for Draft Section 1.4

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Summary of Comments
Section 1.4 - Natural Gas Combustion

Emission Factors

GRI: In Table 1.4-1, small wall-fired and residential furnaces (<100 MMBtu/hr) are grouped in one category. Previous versions had size ranges at <0.3, 0.3 to <10, 10 to <100, and >100 MMBtu/hr. With the present single grouping of <100 MMBtu/hr, the implication is that NO_x, CO, and N_2O emissions are independent of size. Is there data to support this grouping under one size range?

Response: Based on the available data, EPA determined that boiler size had no clear effect on NO_x and CO emissions for boilers less than 100 MMBtu/hr of heat input. The majority of boilers that are smaller than 100 MMBtu/hr are package units and emissions appear to be more dependent on individual boiler operation than boiler size.

Atlanta Gas: The EPA should consider adding a third category to Table 1.4-1 to address either "other" boilers by heat input or address the "ring retention" type boilers. Atlanta Gas has only ring retention type, fire tube, water/glycol boilers. In order for Atlanta Gas to use emission factors versus stack testing on boilers, it would need the previously published emission factors that used heat input or a new category for ring retention.

Response: The EPA changed the small boiler category to include "other" boiler types. In addition, a footnote to Table 1.4-1 provides a conversion factor for heat input: to convert from lb/10^6 scf to lb/MMBtu, divide by 1,020.

GRI: In Table 1.4-1, the value of 84 lb/10^6 scf for CO converts to about 115 ppm, which seems high. In addition, this value implies there is no variation as a function of size. Previous versions had additional size categories. Is there a reason for the change?

Response: The data supports a CO emission factor for wall-fired boilers that is not dependent on size. There were 49 tests conducted on 23 boilers, with an average emission factor of 84.15 and a relative standard deviation of 124 percent. The EPA analyzed CO emissions versus boiler size and determined that there is no clear relation between size and CO emissions. It is true that if CO emissions were averaged across the previous size ranges, the various boiler size categories would have slightly different CO emission factors, but the overall data set showed no clear relation to size. Therefore, CO emission factors were not categorized by size for the wall-fired and small boiler categories. During the next revision of this section, if additional CO

emission data indicates a stronger correlation between size and CO emission levels, then CO emission factors would be distinguished by size.

Burns & McDonnell: Footnote "d" is not properly referenced in Table 1.4-2. It should appear with SO_2 in the pollutant column. Also, EPA should stress that since the emission factors are based on a natural gas heat content of 1,020 Btu/scf, users may need to adjust the emission factors. If the heat content of their natural gas differs from the 1,020 Btu value, users should adjust the emission factor by a ratio of the heat rates (actual Btu heat content /1,020 Btu value). In addition, this same approach applies to the assumed 2,000 grains of sulfur/MMscf for the SO_2 emission rates within the Table 1.4-2.

Response: Footnote "d" has been corrected to properly reference the SO_2 emission factor. Footnote "d" of Table 1.4-2 was also amended to provide guidance on adjusting emission factors for sources firing natural gas with Btu ratings different from 1,020 Btu/scf. A similar approach was taken with the SO_2 emission factor; in this case, EPA provided guidance to adjust the SO_2 emission factor at sources where the sulfur content of the natural gas was different from 2,000 grains/MMscf.

U.S. EPA, EFIG: The CO_2 emission factor in Table 1.4-2 should be 120,000, not 12,000. Also, correct footnote "b" calculation.

Response: The emission factor has been corrected to 120,000 lb/MMscf. The EPA also corrected an error in footnote "b" regarding the calculation of the CO_2 emission factor.

GRI: Table 1.4-2 indicates a conversion of fuel carbon to CO_2 of 99.5%. This converts to about 5,000 ppm of CO and other hydrocarbons. This seems high for commercial boilers. Typical values of CO are less than 50 ppm and other hydrocarbons are typically below 100 ppm. These would result in a conversion efficiency of 99.995% rounded down to 99.9%. Is this value correct?

Response: The assumed fuel carbon conversion as been changed to 99.9%. This adjustment will not change the CO_2 emission factor since it was rounded to two significant figures.

Unidentified commenter via U.S. EPA, EFIG: Put Chemical Abstract Services (CAS) numbers with the Hazardous Air Pollutant (HAP) in the tables. The HAP list in the section is confusing because many of those compounds listed are not listed in section 112(b) of the 1990 Amendments to the Clean Air Act, and they only qualify as HAPs because they are Polycylic Organic Matter (POMs). It would be more clear to label which compounds are HAPs and which are HAPs because they are POMs.

Response: CAS numbers were assigned to all pollutants for easy identification. The EPA also distinguished between HAPs and compounds that are classified as HAPs because they are POMs.

GRI: GRI suggests adding a footnote to the tables to explain to the casual reader the meaning of "emission factor rating."

Response: Rather than footnote each table with an explanation of emission factor ratings, the ratings are discussed at the end of the section. In addition, the EPA fully discusses emission factor ratings in the introduction to AP-42 and in the Emission Factor Documentation for Section 1.4 (background report).

Phillips: The emissions data suggest that grouping the toxics data into specific categories of heaters/boilers could provide more accurate emission factors for air toxics. In the database enclosed with the report, arithmetic averages are used to calculate the criteria pollutant and toxics emission factors. By using arithmetic averages, the assumption is made that the distribution is normal. However, Phillips' review of the normality and probability of the toxics data shows non-random behavior (non-normal distribution). The commenter suggests that, if it has not already been considered, the toxics data may be grouped by heater/boiler heat input to increase the accuracy of the resulting emission factors. (The commenter recognizes that small sample sizes reduce the effectiveness of normality tests.) If this suggested grouping has already been considered and would not work, EPA should discuss this in the background report. Otherwise, EPA should consider a new grouping.

Response: The toxic data were analyzed for these source categories to determine if grouping these data by source type would provide more accurate emission factors. Based on this analysis and given the limited data available, no clear relation is apparent between these source categories

and toxic emission levels. Therefore, EPA maintains that the current grouping is the most appropriate. The background report provides a discussion of this decision.

Phillips: The emission factors for natural gas-fired heaters should be delayed pending the results of the GRI/API/Radian study of engine emissions. A program for characterizing and quantifying emissions from reciprocating engines used in oil and gas production is underway and the data will be available in October 1997. The program will also investigate the emissions from a 62.5 MMBtu/hr boiler and a heater treater which is representative of small heaters used in the oil and gas production industry. The list of analytes chosen for this effort includes those reported in Tables 1.4-2 and 1.4-4. The resulting data meet EPA's criteria for an emission factor rating of "A." The value of the data justifies a short delay in publishing the revised emission factors.

Response: The EPA is aware of the data that will be available in the GRI/API/Radian study but that the final report will not be ready for distribution until early 1998. Given the time frame of the publication of this report, EPA does not want to delay the revision of Section 1.4 of AP-42 to include this data. The EPA understands that the report has data from 1 boiler and that the inclusion of 1 extra boiler in the database should have little effect on the emission factors in this revision. However, the emission test data from the boilers tested in the GRI study will be incorporated in the next revision to Section 1.4.

Phillips: Only emission factors with an emission factor rating of A, B, or C should be published in the public domain. The use of emission factors based on poor quality data may have far-reaching, undesirable consequences.

Response: The primary purpose of AP-42 is to provide emission factors for emission inventories. The EPA provides emission factors for as many sources and as many pollutants as available resources allow. The factors are rated "A" through "E" to provide the user with an indication of how good an emission factor is, with an "A" being excellent and "E" being poor. The criteria that are used to determine a rating for a factor can be found in the document entitled "Procedures for Preparing Emission Factor Documents, EPA-454/R-95-0150." While the EPA shares your concern about poor quality emission factors for various reasons, the factor rating is used to judge whether the factor is appropriate.

Controls

GRI: Section 1.4 states that low-NO_x burners and flue gas recirculation (FGR) are the most prevalent combustion NO_x control techniques being applied to natural gas-fired boilers. GRI agrees that low-NO_x burners are prevalent in all classes and size ranges of boilers. However, GRI does not agree that FGR is prevalent for boilers with capacities less than 100 MMBtu/hr. Also, one NO_x control system not mentioned is gas reburning. Gas reburning is an attractive technical and economic alternative to SNCR or SCR. The commenter cited demonstrations of gas reburn on a tangentially-fired utility boiler, a front-wall boiler, and an opposed-wall boiler. The tangentially-fired boiler achieved a 55-65% reduction of NO_x and the opposed-wall and front-wall burners achieved 80% and 73% reductions, respectively.

Response: The EPA is aware that FGR technology is most prevalent in boilers with heat inputs greater than 100 MMBtu/hr, however, EPA has data from boilers with heat inputs less than 100 MMBtu/hr that employ FGR and low-NO_x burners for NO_x control. The EPA has received tests from several boilers with heat inputs less than 100 MMBtu/hr that have FGR and low-NO_x burners. Furthermore, there is a separate category for the boilers for NO_x emission factors. With respect to gas reburning, EPA does not have any data to evaluate the performance of gas reburning. In the final version of this revision to Section 1.4, gas reburning will be mentioned as a NO_x control technology. However, NO_x reduction efficiencies will not be presented in this revision to Section 1.4 due to the lack of supporting data.

GRI: Section 1.4 states that the addition of low-NO_x burners and FGR may reduce combustion efficiency. This implies that low-NO_x burners and FGR are the direct cause of reduced combustion efficiency. This is not necessarily correct. Incomplete combustion can be unburned fuel, unburned carbon, and newly formed solid, liquid, or gaseous hydrocarbons. One of the later species could be CO. GRI suggests the following revision to the paragraph: "Improperly tuned boilers and boilers operating at off-design levels can result in increased partially oxidized combustibles (e.g., CO) and thus, decreased combustion efficiency. The addition of NO_x control systems such as low-NO_x burners and FGR may also result in increased CO or other partially oxidized combustibles, and likewise, decreased combustion efficiency."

Response: The effects of improperly tuned boilers on CO and hydrocarbon emissions were addressed in the discussions on CO and hydrocarbon emissions. Therefore, GRI's suggestion will not be added.

GRI: It is also worth mentioning that current NO_x control systems can lower NO_x emissions without increases in other emissions such as CO, VOCs, and PM. An example of this is shown in Section 2, Reference 6.

Response: The EPA will add this to its discussion of NO_x control technologies.

GRI: There has been significant testing of minor products of combustion and also significant development of low-NO_x burners and NO_x control technology in recent years. If it is not within EPA's current resources to obtain later information, it would be well to indicate the data in the tables are from sources with publication dates ranging from 1990-1996.

Response: The background report provides a list of all the references used in this revision including testing dates. If users wish to evaluate the age of the data, they can download this document from the TTN.

Emission Data

ABMA and EPRI both provided emission data for natural gas fired boilers. The data provided by ABMA was used for comparative purposes and was not included for emission factor development because it did not contain complete testing information. The data provided by EPRI did contain complete testing information and was used in the development of emission factors.

VOLUME II: CHAPTER 2

PREFERRED AND ALTERNATIVE METHODS FOR ESTIMATING AIR EMISSIONS FROM BOILERS

January 2001

Prepared by:
Eastern Research Group, Inc.

Prepared for:
Point Sources Committee
Emission Inventory Improvement Program

DISCLAIMER

As the Environmental Protection Agency has indicated in Emission Inventory Improvement Program (EIIP) documents, the choice of methods to be used to estimate emissions depends on how the estimates will be used and the degree of accuracy required. Methods using site-specific data are preferred over other methods. These documents are non-binding guidance and not rules. EPA, the States, and others retain the discretion to employ or to require other approaches that meet the requirements of the applicable statutory or regulatory requirements in individual circumstances.

ACKOWLEDGEMENT

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CONTENTS

CONTENTS (CONTINUED)

TABLES

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1

INTRODUCTION

The purposes of the preferred methods guidelines are to describe emission estimation techniques for stationary point sources in a clear and unambiguous manner and to provide concise example calculations to aid in the preparation of emission inventories. This chapter describes the procedures and recommended approaches for estimating emissions from external combustion sources (i.e., boilers).

Section 2 of this chapter contains a general description of the boiler source category, a listing of emission sources commonly associated with boilers, and an overview of the available control technologies for various boiler types. Section 3 of this chapter provides an overview of available emission estimation methods. It should be noted that the use of site-specific emission data is often preferred over the use of industry-averaged data such as *AP-42* emission factors. However, depending upon available resources, site-specific data may not be cost effective to obtain. Section 4 presents the preferred emission estimation methods for boilers by pollutant, and Section 5 presents the alternative emission estimation techniques. Quality assurance (QA) and quality control (QC) procedures are described in Section 6, and data coding procedures are discussed in Section 7. Section 8 lists references. Appendix A provides an example data collection form for boilers to assist in information gathering prior to emissions calculations. Refer to Chapter 1 of this volume, *Introduction to Stationary Point Source Emission Inventory Development*, for general concepts and technical approaches.

This chapter does not specifically discuss State Implementation Plans (SIPs) or base year, periodic, and planning inventories. However, the reader should be aware that the U.S. Environmental Protection Agency (EPA) procedures manuals pertaining to the preparation of emission inventories for carbon monoxide and precursors of ozone are available (EPA, May 1991).

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2

GENERAL SOURCE CATEGORY DESCRIPTION

2.1 SOURCE CATEGORY DESCRIPTION

This section provides a brief overview discussion of boilers. The reader is referred to the *Air Pollution Engineering Manual* (sometimes referred to as *AP-40*) (Buonicore and Davis, 1992) and *AP-42* (EPA, January 1995) for a more detailed discussion on boilers, boiler designs, boiler operations and their influences on emissions.

The boiler source category comprises sources that combust fuels to produce hot water and/or steam. Utility boilers utilize steam to generate electricity. Industrial boilers often generate steam for electrical power as well as process steam. Space heaters use the hot water for heating commercial and residential building space. Fuels typically used in boilers include coal, oil, and natural gas. In addition, liquified petroleum gas (LPG), process and waste gases, and wood wastes may be used. In general, boilers are categorized as follows:

Types of Boilers	Size
Utility	>100 MMBtu/hr
Industrial	10 - 250 MMBtu/hr
Commercial/Institutional	<10 MMBtu/hr
Residential	<<10 MMBtu/hr

These categorizations are general to the types of boilers listed above. It should be noted that regulations developed under the Clean Air Act (such as New Source Performance Standards for Steam Generating Units) may have different size cut-offs for applicability than are listed here.

2.1.1 COAL-FIRED BOILERS

Coal is broadly classified into one of four types (anthracite, bituminous, subbituminous, or lignite) based on differences in heating values and amounts of fixed carbon, volatile matter, ash,

sulfur, and moisture. The following sections discuss the four main types of coal boilers (pulverized coal, cyclone, spreader stoker, and fluidized bed) and the processes that occur at all four types of coal-fired boilers. Pulverized coal and cyclone boilers employ a technique known as suspension firing; they are sometimes categorized by this technique.

Pulverized Coal Furnaces

Pulverized coal furnaces are used primarily in utility and large industrial boilers (Buonicore and Davis, 1992; EPA, January 1995). In a pulverized coal system, the coal is pulverized in a mill to the consistency of talcum powder. The pulverized coal is then entrained in primary air before being fed through the burners to the combustion chamber, where it burns in suspension. Pulverized coal furnaces are classified as either dry or wet bottom, depending on the ash removal technique. Dry-bottom furnaces may either be tangential- or nontangential-fired units. Some examples of nontangential-fired pulverized coal furnaces are wall-fired, turbo, cell-fired, vertical, and arch. Dry-bottom furnaces fire coal with high ash fusion temperatures, whereas wet-bottom furnaces fire coal with low ash fusion temperatures. Wet-bottom furnace designs have higher nitrogen oxides (NO$_x$) emission rates and are no longer being built, though many remain in service.

Cyclone Furnaces

Cyclone furnaces are used mostly in utility and large industrial applications (Buonicore and Davis, 1992). Cyclone furnaces burn coal that has a low ash fusion temperature and has been crushed to a four-mesh size (larger than pulverized coal). Coal in a cyclone furnace is fed tangentially with primary air to a horizontal cylindrical combustion chamber. In this chamber, small coal particles are burned in suspension, while the larger particles are forced against the outer wall. Because of the high temperatures developed in the relatively small combustion chamber and because of the low fusion temperature of the coal ash, much of the ash forms a liquid slag that is drained from the bottom of the furnace through a slag tap opening (EPA, January 1995).

Spreader Stokers

In spreader stokers, a rotating flipping mechanism throws the coal into the furnace and onto a moving fuel bed. Combustion occurs partly in suspension and partly on the grate. Because of significant amounts of carbon in the particulate, fly ash reinjection from mechanical collectors is commonly employed to improve boiler efficiency. Ash residue in the fuel bed is deposited in a receiving pit at the end of the grate (EPA, January 1995). Anthracite coal is not used in spreader stokers because of its low volatile matter content and relatively high ignition temperature.

Fluidized Bed Combustors

In a fluidized bed combustor (FBC), coal is introduced to a bed of either sorbent (limestone or dolomite) or inert material (usually sand) that is fluidized by an upward flow of air. Combustion takes place in the bed at lower temperatures than other boiler types. Key benefits to this relatively new process are fuel flexibility and reduced emissions. FBCs are typically used for industrial-sized boilers and may be emerging as a competitive design for electric power generation (Stultz and Kitto, 1992).

2.1.2 OIL-FIRED BOILERS

There is little variation between the design of oil-fired units and the design of coal-fired units; almost all are either tangential-fired or wall-fired. Fuel oils are broadly classified into two major types: distillate and residual. Distillate oils (fuel oil grade Nos. 1 and 2) are used mainly in domestic and small commercial applications in which easy fuel burning is required. Distillates are more volatile and less viscous than residual oils. Being more refined, they have negligible ash content, and usually contain less than 0.3 weight percent sulfur. Residual oils (grade Nos. 4, 5, and 6) are used mainly in utility, industrial, and large commercial applications with sophisticated combustion equipment. Residual No. 4 oil is sometimes classified as a distillate, and No. 6 is sometimes referred to as Bunker C. The heavier residual oils (grade Nos. 5 and 6) are more viscous and less volatile than distillate oils and, therefore, must be heated to facilitate handling and proper atomization. Because residual oils are produced from the crude oil residue after lighter fractions (gasoline, kerosene, and distillate oils) have been removed, these oils contain significant quantities of ash, nitrogen, and sulfur (EPA, January 1995). However, low-sulfur residual oil is becoming more commonplace.

2.1.3 NATURAL GAS-FIRED BOILERS

Natural gas is used for power generation, industrial process steam and production activities, and domestic and commercial space heating. The primary component of natural gas is methane, although small amounts of ethane, nitrogen, helium, and carbon dioxide (CO_2) can also be present (EPA, January 1995).

Natural gas boilers are considered clean relative to coal- or oil-fired boilers, but improper operating conditions (such as poor air-fuel mixing) may still result in smoke (unburned carbon) in the exhaust, as well as carbon monoxide (CO) and perhaps small amounts of unburned hydrocarbons. NO_x emissions are usually the major pollutants of concern in a well-operated natural gas boiler. NO_x emissions are primarily a function of the combustion chamber temperature.

Several modifications can be made to natural gas boilers to reduce NO_x emissions. Staged combustion can reduce NO_x emissions by 5 to 20 percent (EPA, January 1995); low excess air levels and flue gas recirculation also often lower NO_x emissions.

2.1.4 BOILERS USING OTHER TYPES OF FUEL

Other fuels such as LPG, process gas, wood and/or bark, bagasse and solid/liquid waste may be used in boilers.

LPG is either butane, propane, or a mixture of the two. This gas is often called bottled gas. Grade A LPG is mostly butane and Grade F is mostly propane, with Grades B through E consisting of varying mixtures of butane and propane. Although LPG is considered a clean fuel, gaseous pollutants such as CO, organic compounds (including volatile organic compounds or VOCs), and NO_x are emitted as are small amounts of sulfur dioxide (SO_2).

Process gases that are used for fuel include petroleum refinery gas, blast furnace gas, coke oven gas, landfill gas, and any other process gases with sufficient and economically recoverable heating values.

The burning of wood and/or bark in boilers is mostly confined to situations where steady supplies of wood or bark are available as a byproduct or in close proximity to the boiler. In most cases, the wood is waste that would otherwise present a solid waste disposal problem. The common types of boilers used to burn wood/bark are Dutch ovens, fuel cell ovens, spreader stokers, vibrating grate stokers, and cyclone (tangential-fired) boilers (EPA, January 1995).

Bagasse is the matted cellulose fiber residue from sugar cane that has been processed in a sugar mill. Fuel cells, horseshoe boilers, and spreader stoker boilers are used to burn bagasse.

Solid or liquid waste may consist of general waste solids or liquids, refuse-derived fuel, or waste oil. Waste oil, or used oil, refers to spent lubrication and other industrial oils that would otherwise present a liquid waste disposal problem. The most common type of waste oil is used vehicle crankcase oil. Other oils include metalworking lubricants, animal and vegetable oils and fats, and transformer and other heat transfer fluids. Waste oils may have higher emissions of SO_2 and particulates than refined fuel oils, but will have similar levels of emissions for NO_x, CO, and organic compounds (EPA, January 1995). Heavy metal emissions may be greater from crankcase oil combustion.

2.1.5 COGENERATION UNITS

Cogeneration is the production of more than one useful form of energy (such as process heat and electric power) from the same energy source. Cogeneration plants produce electric power and

also meet the process heat requirements of industrial processes (Cengel and Boles, 1989). A steam turbine, gas-cycle turbine, or combined-cycle turbine can be used to produce power in a cogeneration plant.

In a typical cogeneration plant, energy is transferred to water by burning coal, oil, natural gas, or other (nonfossil) fuels in a boiler. The high-pressure, high-temperature steam leaving the boiler is expanded in a turbine that drives a generator to produce electric power. The low-pressure, low-temperature steam leaving the turbine is used as process heat. Industries likely to use cogenerated process heat are the chemical, pulp and paper, oil production and refining, steel making, food processing, and textile industries. Besides the steam-turbine cycle described above, a gas-cycle or a combined-cycle turbine can be used to produce power in a cogeneration plant (Cengel and Boles, 1989). Combustion turbines are also commonly used for cogeneration.

2.1.6 AUXILIARY SOURCES

Auxiliary sources associated with boilers include fuel storage piles, fuel storage tanks, materials handling, and other sources of fugitive emissions. These sources are often overlooked and not reported as a part of the emission inventory. However, it is essential that these sources be considered in the emission inventory to develop a complete record of the emissions coming from the facility.

Coal storage piles are used to store coal at the boiler site. Material handling involves the receipt of coal, movement of coal to the preparation (crushing) facility, and movement of coal to the boilers, which may result in the release of particulate matter (PM) emissions. A coal-fired boiler may also use fuel oil or gas for the initial light-off of the boilers. In this case, as well as for oil-fired boilers, VOC losses from fuel oil storage tanks should be considered (EPA, January 1995).

Because coal crushing operations can generate a significant amount of fine PM, they should be included in the inventory. Because of the potential for explosion from this fine particulate, crushing operations are typically well controlled (EPA, January 1995).

2.2 EMISSION SOURCES

Air pollutant emissions associated with boilers can occur at the following points/processes. Section 7 lists the source classification codes (SCCs) for these emission points.

2.2.1 MATERIAL HANDLING (FUGITIVE EMISSIONS)

Material handling includes the receipt, movement, and processing of fuel and materials to be used at the boiler facility. Coal, limestone, wood, bark, and solid waste may all be included, and their handling may result in particulate emissions. Organic compound emissions can also result from the transfer of liquid and gaseous fuels. This source category includes storage bins and

open stockpiles, as well as the processes used to transfer these materials (e.g., unloading, loading, and conveying).

2.2.2 STORAGE TANKS

Storage tanks are used to store fuel oils at boiler facilities, and should be inventoried as a source of organic compound emissions. Storage tanks at boiler facilities are usually one of two types: fixed roof or floating roof. Emissions at fixed-roof tanks are typically divided into two categories: working losses and breathing losses. Working losses refer to the combined loss from filling and emptying the tank. Filling losses occur when the organic compounds and VOCs contained in the saturated air are displaced from a fixed-roof vessel during loading. Emptying losses occur when air drawn into the tank becomes saturated and expands, exceeding the capacity of the vapor space. Breathing losses are the expulsion of vapor from a tank through vapor expansion caused by changes in temperature and pressure.

Emissions at floating roof tanks are reported in two categories: standing losses and withdrawal losses. Withdrawal loss is the vaporization of liquid that clings to the tank wall and that is exposed to the atmosphere when a floating roof is lowered by withdrawal of liquid. Standing losses result from wind-induced mechanisms and occur at rim seals, deck fittings, and deck seams (EPA, January 1995).

The TANKS program is commonly used to quantify emissions from oil-fired boilers. Its use at boiler installations should be carefully evaluated because it is a complicated program with a great number of input parameters. It is commonly used at large oil-burning facilities where VOC emissions may be significant. Check with your local or state authority as to whether TANKS is required for your facility. The use of the TANKS program for calculating emissions from storage tanks is discussed in Chapter 1 of Volume II, *Introduction to Stationary Point Source Emissions Inventory Development*. TANKS can be downloaded from the EPA's CHIEF website at www.epa.gov/ttn/chief.

2.2.3 PROCESS EMISSIONS

For boilers, emissions resulting from the process (combustion of fuel to generate hot water and steam) are typically vented to the atmosphere via a stack or vent. The major pollutants of concern from boiler stacks are PM, sulfur oxides (SO_2 and sulfur trioxide [SO_3]), VOC, and NO_x. CO and unburned combustibles, including numerous organic compounds (e.g., benzene) can also be emitted under certain boiler operating conditions. Most of the carbon in fossil fuels is emitted as CO_2 during combustion, and may be inventoried due to its role as a greenhouse gas. Trace metals, such as arsenic and cadmium, may also be emitted as a result of combustion of coal and oil. Additionally, organic pollutants such as formaldehyde, and polycyclic organic matter (POM) may be formed during combustion and emitted (EPA, April 1989). Typical pollutants associated

with boiler emissions are listed in Table 2.2-1 by fuel type. Not all listed pollutants will be emitted in every case, so site-specific pollutant data (from fuel analysis or stack tests) should always be used if available.

2.3 FACTORS AND DESIGN CONSIDERATIONS INFLUENCING EMISSIONS

2.3.1 PROCESS OPERATING FACTORS

The combustion process is defined as the rapid oxidation of substances (fuels) with the evolution of heat. Boilers utilize the heat generated by combustion to produce hot water, steam, or both. The fuel types discussed in this chapter include coal, oil, natural gas, and other fuels such as wood, LPG, and process gases. When these burn, they are converted into CO_2 and water, referred to as the combustion products. The noncombustible portion of a fuel remains as a solid residue or ash. The coarser, heavier portion remains within the combustion chamber and is called "bottom ash." The finer portion, referred to as "fly ash," exits the furnace with the flue gas.

Combustion products from boiler operation can also include partially oxidized hydrocarbons, CO, SO_2, SO_3, NO_x, acids such as hydrochloric acid, and organohalides such as dioxins and furans. The generation of undesirable combustion products is strongly influenced by fuel type, furnace type, firing configuration, and boiler operating conditions. Although a detailed discussion of boiler operations cannot be presented here, some general observations are included to assist in understanding the relative impact of various boilers and fuel types on air emissions.

The discussion on coal-fired boilers introduced the four primary classifications of coal: lignite, anthracite, bituminous, and subbituminous. Fuel is ranked based on American Society for Testing and Materials (ASTM) standard methods referred to as "proximate" and "ultimate" analyses. Proximate analyses report fuel composition in broad categories such as moisture content and ash content. Ultimate analyses provide an estimate of the carbon, hydrogen, sulfur, oxygen, nitrogen, and water content of the fuel. An ultimate analysis is used to compute combustion air requirements and can also be used to calculate fuel factors (F_d) for determining exhaust gas flow rates (see Equation 2.4-4). Sections 3 and 4 discuss how fuel analysis can be used to estimate emissions of sulfur oxides and metals from fuel combustion. Generally, boiler size, firing configuration, and operation have little effect on the percent conversion of fuel sulfur to sulfur oxides, so fuel analysis is typically a valid means of predicting emissions of sulfur oxides.

By contrast, NO_x formation is highly dependent on boiler conditions, especially temperature and air/fuel ratios near the burner. NO_x is produced by three mechanisms: conversion of fuel-

TABLE 2.2-1

POLLUTANTS ASSOCIATED WITH BOILER EMISSIONS

Criteria Pollutants	Hazardous Air Pollutants
Coal	
• Carbon Monoxide • Lead • Nitrogen Oxides • PM-Primary • PM-Filterable • PM-Condensible • PM10-Primary* • PM10-Filterable* • PM2.5- Primary* • PM2.5-Filterable* • Sulfur Oxides	• Antimony & Compounds • Benzene • Beryllium & Compounds • Cadmium & Compounds • Chromium & Compounds • Cobalt Compounds • Dioxin/Furans as 2,3,7,8-TCDD TEQ • Ethylbenzene • Formaldehyde • Hydrogen Chloride • Hydrogen Fluoride • Lead & Compounds • Manganese & Compounds • Mercury & Compounds • Methyl Chloroform (1,1,1-Trichloroethane) • Methyl Ethyl Ketone (2-Butanone) • Nickel & Compounds • Toluene • Xylenes (includes o, m, and p)
Natural Gas	
• Carbon Monoxide • Lead • Nitrogen Oxides • PM-Primary • PM-Filterable • PM-Condensible	• Benzene • Cadmium & Compounds • Chromium & Compounds • Cobalt Compounds • Formaldehyde • Lead & Compounds

TABLE **2.2-1**

(CONTINUED)

Criteria Pollutants	Hazardous Air Pollutants
Natural Gas (Continued)	
• PM10-Primary* • PM10-Filterable* • PM2.5- Primary* • PM2.5-Filterable* • Sulfur Oxides	• Manganese & Compounds • Mercury & Compounds • Nickel & Compounds • Toluene
Oil	
• Carbon Monoxide • Lead • Nitrogen Oxides • PM-Primary • PM-Filterable • PM-Condensible • PM10-Primary* • PM10-Filterable* • PM2.5- Primary* • PM2.5-Filterable* • Sulfur Oxides	• Benzene • Beryllium & Compounds • Cadmium & Compounds • Chromium & Compounds • Cobalt Compounds • Dioxins/Furans as 2,3,7,8-TCDD TEQ • Ethylbenzene • Formaldehyde • Lead & Compounds • Manganese & Compounds • Mercury & Compounds • Methyl Chloroform (1,1,1-Trichloromethane) • Nickel & Compounds • Toluene • Xylenes (includes o, m, and p) • Dioxins/Furans as 2,3,7,8-TCDD TEQ • Ethylbenzene • Formaldehyde • Lead & Compounds • Manganese & Compounds • Mercury & Compounds

* PM10 and PM2.5 refer to PM less than or equal to an aerodynamic diameter of 10μm and 2.5μm, respectively.

bound nitrogen in fuel, oxidation of molecular nitrogen from combustion air (referred to as thermal NO_x formation) and reaction of hydrocarbon fragments and atmospheric nitrogen (prompt NO_x). Thermal NO_x formation is highly temperature dependent and becomes rapid as temperatures exceed 3,000°F (Buonicore and Davis, 1992). Lower operating temperatures result in decreased thermal NO_x production. Shorter residence time also lowers thermal NO_x generation. Prompt NO_x is formed very early in the combustion process and is significant only in very fuel-rich flames.

Fuel NO_x will generally account for over 50 percent of the total NO_x generated by oil- and coal-fired boilers. NO_x emissions from tangential-fired oil boilers are typically lower than those from horizontally opposed units. Many boilers employ combustion modifications to reduce NO_x emissions. These include staged combustion, off-stoichiometric firing, flue gas recirculation, and low-NO_x burners with overfire air (OFA). These control strategies can reduce NO_x emissions by 5 to 50 percent (Buonicore and Davis, 1992). For a more detailed discussion of NO_x control strategies, see Chapter 12 of EIIP Volume II, *How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates.*

The utility sector is dominated by pulverized dry-bottom, coal-fired units. Stoker boilers, currently accounting for a small percentage of total national capacity, are less common. Coal-fired pulverized wet-bottom and cyclone boilers are no longer manufactured due to their inability to meet NO_x standards, although many are still in use.

In the industrial sector, more natural gas is used relative to coal and oil. The commercial/institutional sector consumes a greater proportion of oil and natural gas relative to coal consumption than the other two sectors.

2.3.2 CONTROL TECHNIQUES

Table 2.2-2, "Boiler Controls," lists the control technologies associated with boiler operations, along with their typical efficiencies. Control efficiency for a specific piece of equipment will vary depending on the age of the equipment and quality of the maintenance/repair program at a particular facility.

Particulate Control

In addition to PM and PM with an aerodynamic diameter of less than 10 μm (PM_{10}) emissions, particulate control also serves to remove trace metals, as well as metals (such as lead) that are vaporized in the combustion chamber and condensed onto fly ash in the exhaust. However, the PM control efficiencies listed in Table 2.2-2 may not correspond to actual removal efficiencies of specific hazardous air pollutants (HAPs) or metals, due to the phenomena of fine particle

TABLE 2.2-2

BOILER CONTROLS

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Bagasse	PM	Mechanical Collector		20	60
		Wet PM Scrubber		90	
Coal	NO_x	Flue Gas Recirculation		5	45
		Low Excess Air		5	30
		Low NO_x Burners		35	55
		Natural Gas Burners/Reburn		50	70
		Overfire Air		5	30
		Selective Catalytic Reduction		63	94
		Selective Non-catalytic Reduction		30	60
		Low NO_x Burner w/ Selective Non-catalytic Reduction		50	80
		Low NO_x Burner w/ Overfire Air and Selective Catalytic Reduction		85	95
		Low NO_x Burner w/ Overfire Air		40	60
	SO_2[b]	Wet Acid Gas Scrubber		80	99
		Spray Dryer Absorber		70	90

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Coal (Continued)	PM	Electostatic Precipitator	99	90	99.9
		Fabric Filter	99	99	
		Mechanical Collector	65	90	95
		Wet PM Scrubber		50	99
Coal (Anthracite)	PM	Electrostatic Precipitator	98.4		
		Fabric Filter		98.4	99.4
Coal (Bituminous)	PM	Electrostatic Precipitator		96	99.4
		Fabric Filter		98.3	99.9
	PM-10	Fuel Switching to Sub-bituminous Coal (Industrial Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Industrial Sources)[c]	62.9		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	98.2		

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Coal (Bituminous) (Continued)	PM -10 (Continued)	Fuel Switching to Sub-bituminous Coal (Utility Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Utility Sources)[c]	69.5		
		Fuel Switching to Natural Gas (Utility Sources)[c]	99.3		
	PM - 2.5	Fuel Switching to Sub-bituminous Coal (Industrial Sources)[c]	21.4		
		Fuel Switching to Residual Oil (Industrial Sources)[c]	7.4		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	93.1		
		Fuel Switching to Sub-bituminous Coal (Utility Sources)[c]	21.4		

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Coal (Bituminous) (Continued)	PM - 2.5 (continued)	Fuel Switching to Natural Gas (Utility Sources)[c]	97.5		
Coal (Sub-bituminous)	PM - 10	Fuel Switching to Residual Oil (Industrial Sources)[c]	52.8		
		Fuel Switching to Natural Gas (Industrial Sources)[c]	97.7		
		Fuel Switching to Residual Oil (Utility Sources)[c]	61.2		
		Fuel Switching to Natural Gas (Utility Sources)[c]	99.2		
	PM - 2.5	Fuel Switching to Natural Gas (Industrial Sources)[c]	91.2		
		Fuel Switching to Natural Gas (Utility Sources)[c]	96.8		

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%) Minimum Value	Control Efficiency Range[a] (%) Maximum Value
Lignite	SO₂[b]	Wet Acid Gas Scrubber		90	
	PM	Electrostatic Precipitator		95	99.5
		Mechanical Collector		60	80
Oil, Distillate, No. 2	NOₓ	Flue Gas Recirculation		45	55
		Low Excess Air		2	19
		Overfire Air		20	45
		Selective Catalytic Reduction			90
Oil, Residual, Nos. 4, 5, and 6	NOₓ	Flue Gas Recirculation	21	2	31
		Low Excess Air		5	31
		Overfire Air		24	47
		Selective Catalytic Reduction		70	80
		Selective Non-catalytic Reduction		35	70

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Oil, Residual, Nos. 4, 5, and 6	PM - 10	Fuel Switching to Natural Gas (Industrial Sources)[c]	95.1		
		Fuel Switching to Natural Gas (Utility Sources)[c]	97.9		
	PM - 2.5	Fuel Switching to Natural Gas (Industrial Sources)[c]	92.5		
		Fuel Switching to Natural Gas (Utility Sources)[c]	97.0		
Utility Oil or Natural Gas	NO_x	Flue Gas Recirculation		40	65
Municipal Waste	NO_x	Selective Catalytic Reduction	69		80
Natural Gas	NO_x	Flue Gas Recirculation		49	68
		Low Excess Air		0	31
		Low NO_x Burners		40	85
		Overfire Air	60	13	73
		Selective Catalytic Reduction		80	90

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Natural Gas (Continued)	NO$_x$ (Continued)	Selective Non-catalytic Reduction		35	80
Natural Boiler Gas	NO$_x$	Low NOX Burner w/ Overfire Air		40	50
Sewage Sludge	PM	Wet PM Scrubber		60	99
Wood	NO$_x$	Selective Non-catalytic Reduction		50	70
	PM	Electrostatic Precipitator		93	99.8
		Fabric Filter	98	95.9	99.9
		Mechanical Collector		65	95
		Wet PM Scrubber	90	95	99
		Wet PM Scrubber[d]		92.1	93.3
Wood Bark	PM	Wet PM Scrubber[d]		83.8	85.1

TABLE 2.2-2

(CONTINUED)

Fuel	Pollutant	Control Device Type	Average Control Efficiency[a] (%)	Control Efficiency Range[a] (%)	
				Minimum Value	Maximum Value
Not Identified	SO_2[b]	Wet Acid Gas Scrubber (Chemical Manufacturing) (b)		90	99

Source: EIIP Volume II, Chapter 12, *How to Incorporate the Effects of Air Pollution Control Device Efficiencies and Malfunctions into Emission Inventory Estimates.*

a) A blank field indicates that no data was available for this pollutant, fuel type, and control device.

b) Control device controls SO_x.

c) These are the potential emission reductions from fuel switching. Source: EPA. 1998. *Stationary Source Control Techniques Document for Fine Particulate Matter.* U.S. Environmental Protection Agency. EPA 452/R-97-001.

d) Control efficiency is applicable to general fuel combustion operations.

enrichment. This phenomena may be especially important for metals that volatilize at peak combustion temperatures and condense on particulate at flue gas temperatures downstream.

Electrostatic Precipitators (ESPs). ESPs are widely used to control emissions from coal-fired boilers and account for 95 percent of all utility particulate controls in the United States (Buonicore and Davis, 1992). ESPs are PM control devices that employ electrical forces to remove particles from the flue gas onto collecting plates (EPA, June 1991). The accumulated particles are then knocked or washed off the plates and into collecting hoppers.

Fabric Filters. Fabric filter systems (also called baghouses) filter particles through fabric filtering elements (bags). Particles are caught on the surface of the bags, while the cleaned flue gas passes through. To minimize pressure drop, the bags must be cleaned periodically as the dust layer builds up. Fabric filters can achieve the highest particulate collection efficiency of all particulate control devices. A trend toward using more fabric filters in the electric utility industry is expected because of increasing restrictions on emissions of PM_{10} and the growing use of dry SO_2 control technologies, such as dry injection and spray drying (Buonicore and Davis, 1992).

Multiple Cyclones. The cyclone (also known as a "mechanical collector") is a particulate control device that uses gravity, inertia, and impaction to remove particles from the flue gas. A multiple cyclone consists of numerous small-diameter cyclones operating in parallel. Multiple cyclones are less expensive to install and operate than ESPs and fabric filters, but are not as effective at removing particulates. They are often used as precleaners to remove the bulk of heavier particles from the flue gas before it enters the main control device. They are often used on wood-fired boilers in series with scrubbers, ESPs, or fabric filters (Buonicore and Davis, 1992).

Venturi Scrubbers. Venturi scrubbers (sometimes referred to as high-energy wet scrubbers) are used to remove coarse and fine PM. Flue gas passes through a venturi tube while low-pressure water is added at the throat. The turbulence in the venturi tube promotes intimate contact between the particles and the water. The wetted particles and droplets are collected in a cyclone spray separator (sometimes called a cyclonic demister). Venturi scrubbers are often used on wood-fired boilers. Venturi scrubbers have a relatively high pressure drop, often ranging from 25 to 50 inches of water.

Sulfur Dioxide Control

Dry Scrubbers. Dry scrubbing is sometimes referred to as spray drying or spray absorption. It involves spraying a highly atomized slurry (which may contain water) of an alkaline reagent (slaked lime) into the hot flue gas to absorb the SO_2. The high temperatures of the flue gas evaporates the water (if a wet reagent was used) and a dust collector removes the "dry" reagent which has absorbed the SO_2. Unlike wet scrubbers, the dry scrubber is positioned before the dust

collector. Dry scrubbers are often applied on smaller industrial boilers, waste-to-energy plants, and units burning low-sulfur fuels (Stultz and Kitto, 1992).

Wet Scrubbers. In wet scrubbers, an alkaline liquid slurry is introduced into the flue gas. Wet scrubbing results in the generation of wet waste, which typically must be treated and disposed of in accordance with landfill and wastewater regulations. Limestone scrubbing is widely used on coal-fired utility boilers. Less common are regenerable systems that treat the absorber product to recover reagents, sometimes producing salable gypsum, elemental sulfur, or sulfuric acid.

Low-Sulfur Fuel. This approach to reducing SO_2 emissions reduces the sulfur fed to the combustor by burning low-sulfur coals or oils. Fuel blending is the process of mixing high-sulfur-content fuels with low-sulfur-content fuels. The goal of effective fuel blending is to meet the blend specification, including sulfur content, heating value, moisture content, and (for coal) grindability. This practice is highly effective since most studies estimate that over 95 percent of the fuel sulfur is converted to SO_2 during combustion. The minor amount of sulfur not converted is typically bound in the ash. High-alkali coal tends to bind more SO_2 in the ash.

Nitrogen Oxides Control

Selective Catalytic Reduction. SCR is an add-on control technology that catalytically promotes the reaction between ammonia (which is injected into the flue gas) and NO_x to form nitrogen (N_2) and water. SCR is currently used primarily with natural gas- and oil-fired boilers. In addition, several SCR systems have recently been installed on coal-fired boilers. If sulfur is present in the fuel, ammonium sulfate and bisulfate can form at around 500°F and can deposit on and foul the catalyst. If chlorine is present, ammonium chloride can form at around 250°F and result in a visible plume.

Selective Noncatalytic Reduction. SNCR technologies inject a reducing agent into NO_x-laden flue gas to reduce the NO_x to N_2 and water (H_2O). Two basic processes are currently available, one based on ammonia injection (Thermal $DeNO_x$®), and one based on urea injection (sponsored by the Electric Power Research Institute [EPRI]). Both systems require careful attention to the problem of unreacted ammonia, which can form corrosive ammonia salts that damage downstream equipment.

Low NO_x Burners and Overfire Air. LNB and OFA have been demonstrated to be effective means of lowering NO_x production at utility boilers. These are combustion control methods that reduce peak temperatures in the combustion zone, reduce the gas residence time in the high-temperature zone, and provide a rich fuel/air ratio in the primary flame zone. This is considered a design change although it results in a reduction of emissions.

Low Excess Air. LEA is another combustion modification designed to lower NO_x emissions by inhibiting the creation of thermal NO_x. This is accomplished by limiting the amount of free nitrogen in the combustion zone. Excess air must be present to ensure good fuel use and to prevent smoke formation.

Natural Gas Burner/Reburn. In a reburn configured boiler, reburn fuel (natural gas, oil, or pulverized coal) is injected into the upper furnace region to convert the NO_x formed in the primary fuel's combustion zone to molecular nitrogen and water.

Flue Gas Recirculation (FGR). A portion of flue gas is recycled back to the primary combustion zone. This system reduces NO_x formation by two mechanisms:

- Heating in the primary combustion zone of the inert combustion products contained in the recycled flue gas lowers the peak flame temperature, thereby reducing thermal NO_x formation.

- To a lesser extent, FGR reduces thermal NO_x formation by lowering the oxygen concentration in the primary flame zone.

The recycled flue gas may be pre-mixed with the combustion air or injected directly into the flame zone. Direct injection allows more precise control of the amount and location of FGR.

Staged Overfire Air. Staged combustion, or off-stoichiometric combustion, combusts the fuel in two or more steps. A percentage of the total combustion air is diverted from the burners and injected through ports above the top burner level. The total amount of combustion air fed to the furnace remains unchanged. Initially, fuel is combusted in a primary, fuel-rich, combustion zone. Combustion is completed at lower temperatures in a secondary, fuel-lean, combustion zone. The sub-stoichiometric oxygen introduced with the primary combustion air into the high temperature, fuel-rich zone reduces fuel and thermal NO_x formation. Combustion in the secondary zone is conducted at a lower temperature, reducing thermal NO_x formation.

VOC Control

Boilers do not have controls for organics or VOCs since the combustion process destroys most organic pollutants. Boilers do have residual amounts of organics and HAPs in their exhaust streams, which may be reduced by some add-on controls such as scrubbers used to control other pollutants.

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3

OVERVIEW OF AVAILABLE METHODS FOR ESTIMATING EMISSIONS

3.1 EMISSION ESTIMATION METHODOLOGIES

Several methodologies are available for calculating emissions from boilers. The method used is dependent upon available data, available resources, and the degree of accuracy required in the estimate. In general, site-specific data that are representative of normal operation at that site are preferred over industry-averaged data such as *AP-42* emission factors. For purposes of calculating peak season daily emissions for SIP inventories, refer to the EPA *Procedures* manual (EPA, May 1991).

This section discusses the methods available for calculating emissions from boilers and identifies the preferred method of calculation on a pollutant basis. This discussion focuses on estimating emissions from fuel combustion. Emission estimation approaches for auxiliary processes, such as using EPA's TANKS program to calculate storage tank emissions, are briefly discussed in Chapter 1 of this volume.

3.1.1 CONTINUOUS EMISSION MONITORING SYSTEM (CEMS)

A CEMS provides a continuous record of emissions over an extended and uninterrupted period of time. Various principles are employed to measure the concentration of pollutants in the gas stream; they are usually based on photometric measurements. Once the pollutant concentration is known, emission rates are obtained by multiplying the pollutant concentration by the volumetric stack gas flow rate. The accuracy of this method may be problematic at low pollutant concentrations.

3.1.2 PREDICTIVE EMISSION MONITORING (PEM)

PEM is based on developing a correlation between pollutant emission rates and process parameters and could be considered a hybrid of continuous monitoring, emission factors, and stack tests. A correlation test must first be performed to develop this relationship. Emissions at a later time can then be estimated or predicted using process parameters to predict emission rates based on the results of the initial source test. For example, emissions from a boiler controlled by

an SO_2 scrubber could be predicted, based on the correlation of the scrubbing solution to the pH and flow rate.

3.1.3 STACK SAMPLING

Stack sampling provides a "snapshot" of emissions during the period of the test. Samples are collected using probes inserted into the stack, and pollutants are collected in or on various media and sent to a laboratory for analysis. Some stack test methods provide real time data where the gas sample is analyzed on-site by continuous analysis (e.g., EPA Method 6C and 7E). Pollutant concentrations are obtained by dividing the amount of pollutant collected during the test by the volume of the sample. Emission rates are then determined by multiplying the pollutant concentration by the volumetric stack flow rate. Only experienced stack testers should perform the stack tests. The accuracy of this method may be problematic at low pollutant concentrations.

3.1.4 FUEL ANALYSIS

Fuel analysis data can be used to predict emissions by applying mass conservation laws. For example, if the concentration of a pollutant, or pollutant precursor, in a fuel is known, emissions of that pollutant can be calculated by assuming that all of the pollutant is emitted. This approach is appropriate for pollutants such as metals, SO_2, and CO_2. It should be noted, however, that some of the pollutant may end up in physical or chemical states (ash, unburned hydrocarbons, etc.) not emitted to the atmosphere.

3.1.5 EMISSION FACTORS

Emission factors are available for many source categories and are based on the results of source tests performed at one or more facilities within an industry. Basically, an emission factor is the pollutant emission rate relative to the level of source activity. Chapter 1 of this volume contains a detailed discussion of the reliability, or quality, of available emission factors. EPA provides compiled emission factors for criteria and HAPs in *AP-42*, the locating and estimating (L&E) series of documents, and the Factor Information Retrieval (FIRE) System. These may be found online at: www.epa.gov/ttn/chief/

3.2 COMPARISON OF AVAILABLE EMISSION ESTIMATION METHODOLOGIES

Table 2.3-1 identifies the preferred and alternative emission estimation approach for selected pollutants. For many of the pollutants emitted from boilers, several of the previously defined emission estimation methodologies can be used.

TABLE 2.3-1

SUMMARY OF PREFERRED AND ALTERNATIVE EMISSION
ESTIMATION METHODS FOR BOILERS

Parameter	Preferred Emission Estimation Approach	Alternative Emission Estimation Approach[a]
SO_2	CEMS/PEM data	1. Fuel Analysis[b] 2. Stack sampling data 3. EPA/state published emission factors
NO_x	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
CO	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
CO_2	CEMS/PEM data	1. Stack sampling data 2. Fuel analysis 3. EPA/state published emission factors
VOC[c]	Stack sampling data	EPA/state published emission factors
THC[d]	CEMS/PEM data	1. Stack sampling data 2. EPA/state published emission factors
$PM/PM_{10}/PM_{2.5}/PM_{condensible}$	Stack sampling data	EPA/state published emission factors

TABLE 2.3-1

(CONTINUED)

Parameter	Preferred Emission Estimation Approach	Alternative Emission Estimation Approach[a]
Heavy metals	Fuel analysis[e]	1. Stack sampling data 2. EPA/state published emission factors
Speciated organics	Stack sampling data	EPA/state published emission factors
Sulfuric acid mist	Stack sampling data	EPA/state published emission factors
Flow rate	CFRM[f] data/stack sampling data	1. Stack sampling data 2. EPA/state published emission factors

[a] In most cases, there are several alternative emission estimation approaches.

[b] May be used when no SO_2 control device is present.

[c] There is no direct measurement method for VOC. VOC is defined by EPA as those volatile organic compounds that are photo reactive and contribute to ozone formation. There are 2 common ways for determining VOC. The first is to measure as many of the individual organic compounds as possible and add those that are considered VOC. The second is to measure total hydrocarbons, subtract methane and ethane, and add formaldehyde. The second procedure is more of an estimate of VOC, but is considered acceptable. When using emission factors for VOC and speciated organics it should be noted that the sum of individual organic compounds may exceed the VOC emission factor due to the differences in test methods and the availability of test data for each pollutant.

[d] THC = Total hydrocarbons.

[e] Preferred for oil combustion only when no particulate control device is present; otherwise use stack sampling data.

[f] CFRM = Continuous flow rate monitor.

The preferred method for estimating boiler emissions is to use some form of direct or indirect measurement. This includes stack samples using a standard EPA reference method or other method of known quality, CEMS, or PEM. The preferred method is determined by the time specificity of the emission estimate (i.e., is an average acceptable or is the value on a given day needed?) and the data quality; the quality of the data will depend on a variety of factors including the number of data points generated, the representativeness of those data points, and the proper operation and maintenance of the equipment being used to record the measurements.

For annual emission inventories, CEMS data should always be used if available, and CEM is the preferred method for SO_2, NO_x, CO, CO_2, and THC. PEM also provides an accurate estimate of emissions, but since emissions are not directly measured on a continuous basis, PEM should not be used if CEMS data is available.

In general, short-term stack samples obtained using an EPA reference method will give the highest quality (most accurate) data for any given point in time. However, for long-term estimates (such as annual emissions), CEMS data is expected to provide the most accurate emission estimate as emissions are being measured directly over the entire period of interest.

The performance of CEMS and PEM is measured with respect to the EPA reference method using an index known as relative accuracy (RA). The RA for CEMS or PEM is generally expressed as a percentage, and should have been quantified for any CEMS/PEM installed for regulatory compliance purposes. Also, the stack sampling data used to establish RA should be available; if the standard error of the sample data is greater than the RA, and if the CEMS is known to be adequately maintained, the CEMS data should be used to calculate emissions for any averaging period. The same discussion applies to PEM. For more discussion of statistical measures of uncertainty and data quality, refer to the *Quality Assurance Procedures* in Volume VI of the EIIP Document Series (refer to Section 7 of Chapter 3 and refer to Chapter 4).

3.2.1 CEMS

The use of site-specific CEMS data is preferred for estimating NO_x, CO, CO_2, SO_2, and total hydrocarbon (THC) emissions because it provides a detailed record of emissions over time. Other alternative methods available to estimate emissions of these pollutants provide only short-term emissions data (in the case of stack sampling) or industry averages (in the case of emission factors) that may not be accurate or representative for a specific source.

Instrument calibration drift can be problematic for CEMS and uncaptured data can create long-term incomplete data sets. However, it is misleading to assert that a snapshot (stack sampling) can better predict long-term emission characteristics. It is the responsibility of the source owner to properly operate, calibrate, and validate the monitoring equipment and the corresponding emission data.

The preferred approach for obtaining stack gas flow rate is through the use of continuous monitoring. While flow rate can be measured using short-term stack sampling measurements, continuous monitoring provides more accurate long-term data.

3.2.2 PEM

PEM is a predictive emission estimation methodology whereby emissions are correlated to process parameters based on demonstrated correlations between emissions and process parameters. For example, testing may be performed on a boiler stack while the boiler is operated at various loads. Parameters such as fuel usage, steam production, and furnace temperature are monitored during the tests. These data are then used to produce emission curves. Periodic stack sampling may be required to verify that the emission curves are still accurate or to develop new curves based on the test results.

3.2.3 STACK SAMPLING

Stack sampling is the preferred emission estimation methodology for PM, PM_{10}, speciated organics, and sulfuric acid mist. There are currently no CEMS methods for measuring these pollutants so the use of short-term, site-specific information is preferred over using emission factors that provide averaged emission data for a particular industry.

Fourier Transform Infrared (FTIR) Spectroscopy is a stack sampling method that may be used for multiple pollutants simultaneously. The sampling procedure is described in EPA Test Method 320. It is extractive, meaning flue gas is extracted from the exhaust of the affected source and transported to the FTIR gas cell through a heated handling system. This method applies to the analysis of vapor phase organic or inorganic compounds which absorb energy in the mid-infrared spectral region. This method is used to determine compound-specific concentrations in a multi-component vapor phase sample. Typically, the sampling appartus is similar to that used for single-component CEM measurements.

Spectra of samples are collected using double beam infrared absorption spectroscopy and a computer program is used to analyze spectra and report compound concentrations. Analytes includes HAPs for which EPA reference spectra have been developed. Other compounds can also be measured with this method if reference spectra are prepared according to the protocol. NO_x, CO, CO_2, SO_2, NH_3, formaldehyde, and HCl are commonly sampled and analyzed by FTIR.

3.2.4 FUEL ANALYSIS

Site-specific fuel analysis is the preferred emission estimation methodology for metals when air pollution control equipment (e.g., scrubber, ESP) are not installed. In cases where control

equipment is installed, fuel analysis may be preferred if accurate data are available on pollutant-specific collection efficiencies and the amount of pollutant present in bottom ash and fly ash are known. Once the pollutant concentrations are known, their emissions can be calculated based on mass conservation laws. Fuel analysis is also useful in determining SO_2 and CO_2 emissions. While emission factors are available for most metals, the use of site-specific fuel analysis data provides a more accurate emission estimate. For SO_2, fuel analysis, (specifically, the percentage of sulfur in the fuel) may be used with the appropriate emission factors in AP-42 to estimate SO_2 emissions. Fuel analysis may also be used to calculate CO_2 emissions by assuming complete conversion of the carbon in the fuel to CO_2.

3.2.5 EMISSION FACTORS

Due to their availability and acceptance in the industry, emission factors are commonly used to prepare emission inventories. However, the emission estimate obtained from using emission factors is based upon emission testing performed at similar facilities and may not accurately reflect emissions at a single source. Thus, the user should recognize that, in most cases, emission factors are averages of available industry-wide data with varying degrees of quality and may not be representative for an individual facility within that industry.

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4

PREFERRED METHODS FOR ESTIMATING EMISSIONS

The preferred method for estimating emissions of most pollutants emitted from boilers is usually the use of site-specific information (either CEMS data, PEM data, or recent stack tests). This section provides an outline for calculating emissions from boilers based on raw data collected by the CEMS and stack tests. The CEMS is usually used to measure SO_2, NO_x, THC, CO, flow rate, and a diluent, which can be either oxygen (O_2) or CO_2.

For oil combustion, fuel analysis is the preferred method for estimating emissions of metals.

For PM, sulfuric acid mist, speciated organic emissions, metals from coal combustion, and metals from fuel oil combustion where a particulate control device is used, the preferred emission estimation method is the use of stack sampling test data. Table 2.4-1 lists the variables and symbols used in the following discussion.

4.1 EMISSION CALCULATIONS USING CEMS DATA

To monitor SO_2, NO_x, THC, and CO emissions using a CEMS, a facility uses a pollutant concentration monitor, which measures concentration in parts per million by volume dry air (ppmvd). Flow rates are measured using a volumetric flow rate monitor, a type "S" pitot tube (as in EPA Method 2) or they can be estimated based on heat input using fuel factors, or "F-Factors".

Table 2.4-2 presents an example output from a boiler using a CEMS consisting of SO_2, NO_x, CO, O_2, and flow rate monitors. The output usually includes pollutant concentration in parts per million (ppm) and emission rates in pounds per hour (lb/hr).

The measurements presented in Table 2.4-2 represent a "snapshot" of a boiler's operation; in this case, over a time period of 1 hour and 45 minutes. From these data, it is possible to determine that between 11:00 a.m. and noon, emissions of SO_2 averaged 1,631 (lb/hr). Assuming the CEMS operates properly all year long, an accurate emission estimate can be made by summing the hourly emission estimates.

TABLE 2.4-1

LIST OF VARIABLES AND SYMBOLS

Variable	Symbol	Units
Concentration	C	parts per million by volume dry air (ppmvd)
Molecular weight	MW	lb/lb-mole
Molar volume	V	cubic feet (ft^3)/lb-mole
Flow rate	Q	dry standard cubic feet per minute (dscfm) or actual cubic feet per minute (acfm)
Hourly emissions	E_x	typically lb/hr of pollutant x
Heat input rate	H_{in}	million British thermal units (Btu) per hour (MMBtu/hr)[a]
Annual heat input rate	$H_{in,ann}$	MMBtu/yr
Annual emissions	$E_{tpy,x}$	tons per year (tpy) of pollutant x
Higher heating value	HHV	Btu/lb
Fuel factor (dry)	F_d	dscf/MMBtu at 0% O_2
Filter catch	C_f	g
Metered volume	V_m	ft^3
Fuel flow	Q_f	typically, lb/hr
Annual fuel use	$Q_{f,ann}$	lb/yr
Emission factor	EF_x	typically lb/MMBtu, lb/ft^3, or lb/gal of pollutant x
Annual Op hours	OpHrs	annual operating hours (hr/yr)

[a] MMBtu = 10^6 Btu.

TABLE 2.4-2

EXAMPLE CEMS OUTPUT FOR A BOILER BURNING NO. 6 FUEL OIL

Period	O_2 (%V)	SO_2 (C) (ppmvd)	NO_x (C) (ppmvd)	CO (C) (ppmvd)	Fuel Rate (Q_f) (10^3lb/hr)	Stack Gas Flow Rate (Q) (dscfm)	Emissions			
							SO_2[a] (lb/MMBtu)	NO_x[a] (lb/MMBtu)	SO_2 (lb/hr)	NO_x (lb/hr)
11:00	2.1	1,004.0	216.2	31.5	46.0	155,087	1.9	0.4	1,551	240
11:15	2.0	1,100.0	200.6	25.5	46.5	155,943	2.0	0.4	1,709	224
11:30	2.1	1,050.0	216.7	25.1	46.0	155,087	2.0	0.4	1,622	241
11:45	1.9	1,070.0	220.5	20.8	46.2	154,122	2.0	0.4	1,643	243
12:00	1.9	1,070.0	213.8	19.4	46.8	156,123	2.0	0.4	1,664	239
12:15	1.8	1,050.0	214.0	19.4	46.3	153,647	1.9	0.4	1,607	235
12:30	2.0	1,100.0	209.1	21.5	46.3	155,273	2.0	0.4	1,701	232
12:45	2.0	1,078.0	210.8	50.3	46.5	155,943	2.0	0.4	1,675	235

[a] Based on a fuel heating value of 18,000 Btu/lb.

4.1.1 CALCULATING HOURLY EMISSIONS FROM CONCENTRATION MEASUREMENTS

Although CEMS can report real-time hourly emissions automatically, it may be necessary to manually estimate predicted annual emissions from hourly concentration data. This section describes how to calculate emissions from raw CEMS concentration data.

Hourly emissions can be based on concentration measurements as shown in Equation 2.4-1.

$$E_x = \frac{(C * MW * Q * 60)}{(V * 10^6)} \tag{2.4-1}$$

where:

60 = 60 min/hr
E_x = Hourly emissions in lb/hr of pollutant x
C = Pollutant concentration in ppmvd
MW = Molecular weight of the pollutant (lb/lb-mole)
Q = Stack gas volumetric flow rate in dscfm
V = Volume occupied by 1 mole of ideal gas at standard temperature and pressure (385.5 ft³/lb-mole @ 68°F and 1 atm)

4.1.2 CALCULATING STACK GAS FLOW RATE

When direct measurements of stack gas flow rates are not available, Q can be calculated using fuel factors (F factors) according to EPA Method 19 as shown below.

$$Q = F_d * \frac{20.9}{(20.9 - \%O_2)} * \frac{H_{in}}{60} \tag{2.4-2}$$

where:

F_d = Fuel factor, dry basis (from EPA Method 19) in dscf/MMBtu
$\%O_2$ = Measured oxygen concentration, dry basis expressed as a percentage
H_{in} = Heat input rate in MMBtu/hr

The F factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel. F_d includes all components of combustion less water. F_d can be calculated from fuel analysis results using the following equation:

$$F_d = \frac{10^6 \ [3.64(\%H)+1.53(\%C)+0.57(\%S)+0.14(\%N)-0.46(\%O)]}{HHV} \qquad (2.4\text{-}3)$$

where:

H, C, S, N, and O   =   Concentrations of hydrogen, carbon, sulfur, nitrogen, and oxygen in the fuel expressed as a percentage as determined by a fuel analysis

HHV   =   Higher heating value of the fuel in Btu/lb

Fuel heating values are available in publications such as *Steam, Its Generation and Use* (Stultz and Kitto, 1992). The average F_d factors are provided in EPA Reference Method 19 for different fuels and are shown in Table 2.4-3.

4.1.3 CALCULATING EMISSION FACTORS FROM HEAT INPUT

Sometimes it is desirable to calculate emissions in terms of pounds of pollutant per unit of heat combusted. For regulatory purposes, heat input is calculated based on the HHV of the fuel as measured by analysis. The heat input in terms of MMBtu/hr is calculated using:

$$H_{in} = \frac{(Q_f \ * \ HHV)}{10^6} \qquad (2.4\text{-}4)$$

where:

H_{in} =   Heat input rate in MMBtu/hr
Q_f =   Mass fuel flow rate in lb/hr
HHV   =   Higher heating value in Btu/lb

An emission factor relating emissions to the heat input rate for the boiler is expressed as:

$$EF_x = E_x/H_{in} \qquad (2.4\text{-}5)$$

where:

EF_x =   Emission factor in lb/MMBtu of pollutant x
E_x =   Emissions of pollutant x in lb/hr

TABLE 2.4-3

F_d FACTORS FOR VARIOUS FUELS[a]

Fuel Type	F_d	
	dscm/J[b]	dscf/MMBtu
Coal		
Anthracite[c]	$2.71 * 10^{-7}$	10,100
Bituminous[c]	$2.62 * 10^{-7}$	9,780
Lignite	$2.65 * 10^{-7}$	9,860
Oil[d]	$2.65 * 10^{-7}$	9,190
Gas		
Natural	$2.34 * 10^{-7}$	8,710
Propane	$2.34 * 10^{-7}$	8,710
Butane	$2.34 * 10^{-7}$	8,710
Wood	$2.48 * 10^{-7}$	9,240
Wood Bark	$2.58 * 10^{-7}$	9,600

[a] Determined at standard conditions: 20°C (68°F) and 760 mm Hg (29.92 in. Hg).
[b] dscm/J = Dry standard cubic meters per joule.
[c] As classified according to ASTM Method D 388-77.
[d] Crude, residual, or distillate.

4.1.4 CALCULATING EMISSION FACTORS USING EPA METHOD 19

EPA Method 19 may be used to develop site-specific emission factors (EF_x) for PM, SO_2, and NO_x from pollutant concentration data, Oxygen percentage in the gas stream, and F factors (Fd) using:

$$EF_x = (C_d * F_d)/ [20.9/(20.9 - \%O_2)] \qquad (2.4\text{-}6)$$

where:

$$EF_x = \text{Emission factor in lb/MMBtu of pollutant x}$$
$$C_d = \text{pollutant concentration (lb/dscf)}$$
$$F_d = \text{F factor (dscf/MMBtu)}$$

Example 2.4-1 illustrates the use of Equation 2.4-6.

<u>Example 2.4-1</u>

This example shows how a site-specific SO_2 emission factor may be calculated using stack test data and the EPA Method 19 equation 2.4-6:

$$EF_{SO2} = (C_d * F_d)/[20.9/(20.9 - \%O_2)]$$

The relevant data for this example is:

$$C_{ppm} = 1,000 \text{ ppm}$$
$$F_d = 9,190 \text{ (dscf/MMBtu), from Table 2.4-3}$$
$$\%O_2 = 2.1 \text{ (from the testing data presented in Table 2.4-2)}$$

To convert C_{ppm} to C_d, use the appropriate conversion factor (1.66×10^{-7}) from EPA Method 19:

$$C_d = C_{ppm} * (1.66 - 10^{-7})$$
$$= 1,000 * (1.66 - 10^{-7})$$
$$= 1.66 * 10^{-4}$$

The site-specific emission factor is then calculated as follows:

$$EF_{SO2} = (C_d * F_d)/[20.9/(20.9 - \%O_2)]$$
$$EF_{SO2} = (1.66 \times 10^{-4} * 9,190)/[20.9/(20.9 - 2.1)]$$
$$EF_{SO2} = 1.7 \text{ (lb/MMBtu)}$$

4.1.5 CALCULATING ACTUAL ANNUAL EMISSIONS

Emissions in tons per year can be calculated either by multiplying the average hourly emission rate by the number of annual operating hours (Equation 2.4-7) or by multiplying the average

emission factor in lb/MMBtu by the annual heat input (Equation 2.4-9). Equation 2.4-8 shows how to calculate the annual heat input. Example 2.4-2 depicts the use of these equations.

$$E_{tpy,x} = E_x * OpHrs/2,000$$ (2.4-7)

where:

$E_{tpy,x}$ =   Actual annual emissions in ton/yr of pollutant x
E_x =   Emissions of pollutant x in lb/hr
OpHrs =   Operating hours per year
2,000   =   lb/ton

Annual heat input may be calculated from annual fuel use using:

$$H_{in,ann} = \frac{(Q_{f,ann} * HHV)}{10^6}$$ (2.4-8)

where:

$H_{in,ann}$ =   Annual heat input rate in MMBtu/yr
$Q_{f,ann}$ =   Annual fuel flow rate in lb/yr
HHV   =   Higher heating value in Btu/lb

$$E_{tpy,x} = EF_x * H_{in,ann}$$ (2.4-9)

where:

$E_{tpy,x}$ =   Actual annual emissions of pollutant x in ton/yr
EF_x =   Emission factor in lb/MMBtu of pollutant x

E_{fx} may be obtained using either Equation 2.4-5 or 2.4-6, depending on available data.

Example 2.4-2

This example shows how SO_2 emissions can be calculated based on the raw CEMS data
for 11:00 shown in Table 2.4-2. Hourly emissions are calculated using Equation 2.4-1:

$$E_{SO2} = (C * MW * Q * 60)/(V * 10^6)$$
$$= 1,004 * 64 * 155,087 * 60/(385.5 * 10^6)$$
$$= 1,551 \text{ lb/hr}$$

Heat input is calculated using Equation 2.4-4:

$$H_{in} = (Q_f * HHV)/10^6$$
$$= 46,000 * 18,000/10^6$$
$$= 828 \text{ MMBtu/hr}$$

An emission factor, in terms of lb/MMBtu, is calculated using Equation 2.4-5:

$$EF_{SO2} = E_{SO2}/H_{in}$$
$$= 1,551/828$$
$$= 1.9 \text{ lb/MMBtu}$$

Emissions in tpy (based on a 5,840 hr/yr operating schedule) can then be calculated using
Equation 2.4-7:

$$E_{tpy,SO2} = E_{SO2} * OpHrs/2,000$$
$$= 1,551 * (5,840/2,000)$$
$$= 4,529 \text{ tpy}$$

Emissions in tpy (based on $2.69 * 10^8$ lb annual fuel use) can then be calculated by first
using Equation 2.4-8 to calculate annual heat input:

$$H_{in,ann} = (Q_{f,ann} * HHV)/10^6$$
$$= (2.69 * 10^8 * 18,000)/10^6$$
$$= 4.84 * 10^6 \text{ MMBtu/yr}$$

Example 2.4-2 (Continued)

Emissions in tpy (based on $4.84 * 10^6$ MMBtu/yr) can then be calculated using
Equation 2.4-9:

$$
\begin{aligned}
E_{tpy,SO2} \quad &= \quad EF_{SO2} * H_{in,ann}/2,000 \\
&= \quad 1.9 * 4.84 * 10^6/2,000 \\
&= \quad 4,598 \text{ tpy}
\end{aligned}
$$

Note that the last two calculations in Example 2.4-1 show an actual annual emission
estimate based on a 15-minute average and are provided as an example only. Average
values of E_x should be used to obtain a representative annual emissions estimate.

4.2 PEM

This section outlines an example of SO_2 emission monitoring that could be used to develop a
PEM protocol for a boiler equipped with a wet scrubber. Boiler and scrubber parameters that
affect emissions and that are most likely to be included in the testing algorithm are scrubber
water pH and flow rate, and fuel combustion rate.

To develop this algorithm, correlation testing of the stack gas, scrubber, and boiler process
variables could be conducted over a range of potential operating conditions using EPA
Method 6A or Method 6C to measure SO_2 emissions. Potential testing conditions are shown in
Table 2.4-4. Based on the test data, a mathematical correlation can be developed that predicts
SO_2 emissions using these parameters.

4.3 EMISSION CALCULATIONS USING STACK SAMPLING DATA

Stack sampling test reports often provide emissions in terms of lb/hr or lb/MMBtu. Annual
emissions may be calculated from these data using Equations 2.4-6 or 2.4-8 as shown in
Example 2.4-1. Stack tests performed under a proposed permit condition or a maximum
emissions rate may not accurately reflect the emissions that would result under normal operating
conditions. Therefore, when using stack sampling test data to estimate emissions, tests should be
conducted under "normal" operating conditions.

TABLE 2.4-4

PREDICTIVE EMISSION MONITORING ANALYSIS[a]

Test Number	Scrubber Water Flow Rate	Scrubber Water pH	Fuel Firing Rate
1	B	H	H
2	B	H	M
3	B	H	L
4	B	M	H
5	B	M	M
6	B	M	L
7	B	L	H
8	B	L	M
9	B	L	L

[a] H = High.
    M = Medium.
    L = Low.
    B = Baseline.

Example 2.4-3

This example shows how to calculate SO_2 emissions when the stack gas flow rate, Q, is not available.

The F factor for No. 6 fuel oil, based on Table 2.4-3, is 9,190 dscf/MMBtu. The oxygen content is 2.1 percent. From Example 2.4-1, H_{in} is 828 MMBtu/hr. The stack gas flow rate is calculated using Equation 2.4-10:

$$Q = F_d * (20.9)/(20.9 - \%O_2) * (H_{in}/60) \tag{2.4-10}$$
$$Q = 9,190 * (20.9)/(20.9 - 2.1) * (828/60)$$
$$Q = 140,988 \text{ dscfm}$$

Using the CEMS data from Table 2.4-2 (for 11:00) and the calculated flow rate, hourly emissions can now be calculated using Equation 2.4-1:

$$E_{SO2} = (C * MW * Q * 60)/(V * 10^6) \tag{2.4-1}$$
$$E_{SO2} = (1,004 * 64 * 140,988 * 60)/(385.5 * 10^6)$$
$$E_{SO2} = 1,410 \text{ lb/hr}$$

To express the emissions in terms of pounds per unit of heat combusted, use Equation 2.4-11:

$$EF_{SO2} = E_{SO2}/H_{in} \tag{2.4-11}$$
$$EF_{SO2} = 1,410/828$$
$$EF_{SO2} = 1.7 \text{ lb/MMBtu}$$

Note that E_{SO2} and EF_{SO2} calculated using F factors is slightly different than the emissions calculated using flow rate measurements. This difference is due to different estimation approaches; depending on the use of the data, either approach may be acceptable.

This section shows how to calculate emissions in lb/hr based on raw stack sampling data. Calculations involved in determining SO_2 and PM_{10} emissions from raw EPA Method 201A data are presented in Examples 2.4-3 and 2.4-4, respectively. Because PM_{10} emissions cannot be measured continuously, the best method available for measuring PM_{10} emissions is Method 201A.

An example summary of a Method 201A test is shown in Table 2.4-5. The table shows the results of three different sampling runs conducted during one test event. The source parameters measured as part of a Method 201A run include gas velocity and moisture content, which are used to determine exhaust gas flow rates in dscfm. The filter weight gain is determined gravimetrically and divided by the volume of gas sampled as shown in Equation 2.4-12 to determine the PM concentration in lb/dscf. Pollutant concentration is then multiplied by the volumetric flow rate to determine the emission rate in pounds per hour, as shown in Equation 2.4-1.

$$E_x = (C_f/V_m) * Q * 60/453.6 \qquad\qquad (2.4\text{-}12)$$

where:

E_x	=	Emissions of pollutant x in lb/hr
C_f	=	Filter catch (g)
V_m	=	Metered volume of sample (ft^3)
Q	=	Stack gas volumetric flow rate (dscfm)
60	=	60 min/hr
453.6	=	453.6 g/lb

Example 2.4-4

This example shows how PM_{10} emissions may be calculated using Equation 2.4-12 and the stack sampling data for Run 1 (presented in Table 2.4-5).

E	=	$(C_f/V_m) * Q * 60/453.6$
	=	$(0.003/120.23) * 206,404 * 60/453.6$
	=	0.68 lb/hr

4.4 EMISSION CALCULATIONS USING FUEL ANALYSIS DATA

Fuel analysis can be used to predict emissions based on application of conservation laws. The presence of certain elements in fuels may be used to predict their presence in emission streams. This includes toxic elements such as metals found in oil as well as other elements such as sulfur that may be converted to other compounds during the combustion process.

TABLE 2.4-5

SAMPLE TEST RESULTS - METHOD 201A

Parameter	Run 1	Run 2	Run 3
Total sampling time (minutes)	180.00	180.00	180.00
Corrected barometric pressure (in. Hg)	30.56	30.56	30.56
Absolute stack pressure, Ps (in. Hg)	30.49	30.49	30.49
Stack static pressure (in. H_2O)	-0.89	-0.89	-0.89
Average stack temperature (°F)	328.00	330.00	335.00
Stack area (ft^2)	113.09	113.09	113.09
Metered volume of sample, V_m (ft^3)	116.51	110.20	115.30
Average meter pressure (in. H_2O)	0.81	0.81	0.81
Average meter temperature (°F)	69.28	71.00	70.20
Moisture collected (g)	258.50	265.00	261.00
Carbon dioxide concentration (%V)	15.50	15.40	15.30
Oxygen concentration (%V)	2.30	2.30	2.30
Nitrogen concentration (%V)	82.20	82.30	82.40
Dry gas meter factor	1.01080	1.01080	1.01080
Pitot constant	0.84	0.84	0.84
PM_{10} filter catch (g)	0.003	0.004	0.003
Average sampling rate (dscfm)	0.67	0.67	0.67
Standard metered volume, V_m (std) (dscf)	120.23	121.30	118.50
Standard volume water vapor, Vw (scf)	12.19	13.00	12.50
Stack moisture (%V)	9.20	9.50	9.60
Mole fraction dry stack gas	0.908	0.908	0.908
Dry molecular weight (g)	29.37	29.37	29.37
Wet molecular weight (g)	28.32	28.32	28.32
Stack gas velocity, V_s (ft/min)	3000.00	2950.00	2965.00
Volumetric flow rate (acfm)	339270	333616	335312
Volumetric flow rate (dscfm)	206404	201791	201319
Percent isokinetic	96.48	97.00	98.00
Concentration of particulate (g/dscf)	0.00002	0.00003	0.00003
PM_{10} emission rate (lb/hr)	0.68	0.90	0.69

The basic equation used in fuel analysis emission calculations is:

$$E = Q_f * \text{Pollutant concentration in fuel} * \left(\frac{MW_p}{MW_f} \right)$$

(2.4-13)

where:

Q_f	$=$	Fuel flow rate (lb/hr)
MW_p	$=$	Molecular weight of pollutant emitted (lb/lb-mole)
MW_f	$=$	Molecular weight of pollutant in fuel (lb/lb-mole)

For example, SO_2 emissions from oil combustion can be calculated based on the concentration of sulfur in the oil. This approach assumes complete conversion of sulfur to SO_2. Therefore, for every pound of sulfur (MW = 32 g) burned, 2 lb of SO_2 (MW = 64 g) are emitted. The application of this emission estimation technique is shown in Example 2.4-5.

Example 2.4-5

This example shows how SO_2 emissions can be calculated from oil combustion based on fuel analysis results and the fuel flow information provided in Table 2.4-2.

E_{SO2} may be calculated using Equation 2.4-13.

Q_f	= 46,000 lb/hr
Percent sulfur (%S) in fuel	= 1.17

E_{SO2}	=	Q_f * Pollutant concentration in fuel * (MW_p/MW_f)
	=	(46,000) * (1.17/100) * (64/32)
	=	1,076 lb/hr

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5

ALTERNATIVE METHODS FOR ESTIMATING EMISSIONS

5.1 EMISSION FACTOR CALCULATIONS

Emission factors are commonly used to calculate emissions from boilers when site-specific stack monitoring data are unavailable. The EPA maintains a compilation of emission factors in *AP-42* (EPA, January 1995) for criteria pollutants and HAPs. The most comprehensive source for toxic and hazardous air pollutant emission factors is the FIRE data system (EPA, September 2000). FIRE also contains emission factors for criteria pollutants.

Much work has been done recently on developing emission factors for HAPs and recent *AP-42* revisions have included these factors. In addition, many states have developed their own HAP emission factors for certain source categories and may require their use in any inventories including HAPs. Refer to Chapter 1 of Volume II for a complete discussion of available information sources for locating, developing, and using emission factors as an estimation technique.

Emission factors developed from measurements for a specific boiler may sometimes be used to estimate emissions at other sites. For example, a company may have several boilers of a similar model and size; if emissions were measured from one boiler, a factor can be developed and applied to the other boilers. It is advisable to have the factor approved by state/local agencies or by the EPA.

The basic equation used in emission factor emissions calculations is:

$$E_x = EF_x * \text{Activity Rate} \tag{2.5-1}$$

where:

E_x = Emissions of pollutant x
EF_x = Emission factor

In cases where more than one fuel type is used, annual emissions should be calculated using appropriate emission factors and proportioned based on the amount of each type of fuel used. Examples 2.5-1 and 2.5-2 show the use of Equations 2.5-1.

Example 2.5-1

This example shows how CO emissions may be calculated for No. 6 oil combustion based on the boiler fuel rate information provided in Table 2.4-2 and a CO emission factor from *AP-42*, Table 1.3-2, for No. 6 fuel oil.

$$E_x = EF_x * \text{Activity Rate } (Q_f)$$

$$EF_{CO} = 5 \text{ lb/}10^3 \text{ gal}$$

$$
\begin{aligned}
Q_f &= (46.0 * 10^3 \text{ lb/hr}) * 1 \text{ gal/8 lb} \\
&= 5,750 \text{ gal/hr}
\end{aligned}
$$

$$
\begin{aligned}
E_{CO} &= EF_{CO} * Q_f \\
&= 5/10^3 * 5,750 \\
&= 28.75 \text{ lb/hr}
\end{aligned}
$$

Example 2.5-2

This example shows how chromium emissions may be calculated for No. 6 oil combustion based on a heat input rate of 828 MMBtu/hr and a chromium emission factor from FIRE for SCC 1-01-004-01.

$$EF(\text{chromium}) = 6.31 * 10^{-6} \text{ lb/MMBtu}$$

$$
\begin{aligned}
\text{Chromium emissions} &= EF(\text{chromium}) * H_{in} \\
&= (6.31 * 10^{-6}) * 828 \\
&= 5.22 * 10^{-3} \text{ lb/hr}
\end{aligned}
$$

6

QUALITY ASSURANCE/QUALITY CONTROL

The consistent use of standardized methods and procedures is essential in the compilation of reliable emission inventories. QA and QC of an inventory is accomplished through a set of procedures that ensure the quality and reliability of data collection and analysis. These procedures include the use of appropriate emission estimation techniques, applicable and reasonable assumptions, accuracy/logic checks of computer models, checks of calculations, and data reliability checks. Chapter 3 of Volume VI of this series describes additional QA/QC methods and tools for performing these procedures.

Chapter 1, *Introduction to Stationary Point Source Emission Inventory Development*, of this volume presents recommended standard procedures to follow that ensure the reported inventory of this volume data are complete and accurate. Chapter 1, Section 9, should be consulted for current EIIP guidance for QA/QC checks for general procedures, recommended components of a QA plan, and recommended components for point source inventories. The QA plan discussion includes recommendations for data collection, analysis, handling, and reporting. The recommended QC procedures include checks for completeness, consistency, accuracy, and the use of approved standardized methods for emission calculations, where applicable. Chapter 1, Section 9, also describes guidelines to follow in order to assure the quality and validity of the data from manual and continuous emission monitoring methodologies used to estimate emissions.

6.1 GENERAL FACTORS INVOLVED IN EMISSION ESTIMATION TECHNIQUES

6.1.1 STACK TESTS AND CEMS

Data collected via CEMS, PEM, or stack tests must meet quality objectives. Stack test data must be reviewed to ensure that the test was conducted under normal operating conditions and that data were generated according to an acceptable method for each pollutant of interest. Calculation and interpretation of accuracy for stack testing methods and CEMS are described in detail in *Quality Assurance Handbook for Air Pollution Measurements Systems: Volume III. Stationary Source Specific Methods (Interim Edition)* (EPA, April 1994).

The acceptance criteria, limits, and values for each control parameter associated with manual sampling methods, such as dry gas meter calibration and leak rates, are summarized in of Chapter 1 of this volume. Continuous monitoring for NO_x, CO, CO_2, and THCs using various instruments is discussed in Section 3 of this chapter. QC procedures for all instruments used to continuously collect emissions data are similar. The primary control check for precision of the continuous monitors is daily analysis of control standards. The CEMS acceptance criteria and control limits are also listed in Chapter 1.

6.1.2 EMISSION FACTORS

The use of emission factors is straightforward when the relationship between process data and emissions is direct and relatively uncomplicated. When using emission factors, the user should be aware of the quality indicator associated with the value. Emission factors published within EPA documents and electronic tools have a quality rating applied to them. The lower the quality indicator, the more likely that a given emission factor may not be representative of the source type. It is always better to rely on actual stack test or CEMS data, where available. The reliability and uncertainty of using emission factors as an emission estimation technique are discussed in detail in Chapter 1 of this volume.

6.2 DATA ATTRIBUTE RATING SYSTEM (DARS) SCORES

One measure of emission inventory data quality is the DARS score (Beck et al. 1994). Four examples are given here to illustrate DARS scoring using the preferred and alternative methods. The DARS provides a numerical ranking on a scale of 1 to 10 for individual attributes of the emission factor and the activity data. Each score is based on what is known about the factor and the activity data, such as the specificity to the source category and the measurement technique employed. The composite attribute score for the emissions estimate can be viewed as a statement about the confidence that can be placed in the data. For a complete discussion of DARS and other rating systems, see the *QA Source Document* (Volume VI, Chapter 4) and Volume II, Chapter 1, *Introduction to Stationary Point Source Emission Inventory Development*. These are available on the EIIP web page at www.epa.gov/ttn/chief/eiip/.

Each of the examples below is hypothetical. A range is given where appropriate to cover different situations. The scores are assumed to apply to annual emissions from a boiler. Table 2.6-1 gives a set of scores for an estimate based on CEMS/PEM data. A perfect score of 1.0 is achievable using this method if data quality is very good. Note that maximum scores of 1.0 are automatic for the source definition and spatial congruity attributes. Likewise, the temporal congruity attribute receives a 1.0 if data capture is greater than 90 percent; this assumes that data are sampled adequately throughout the year. The measurement attribute score of 1.0 assumes that the pollutants of interest were measured directly. A lower score is given if the

emissions are speciated using a profile, or if the emissions are used as a surrogate for another pollutant. Also, the measurement/method score can be less than 1.0 if the relative accuracy is poor (e.g., >10 percent), if the data are biased, or if data capture is closer to 90 percent than to 100 percent.

TABLE 2.6-1

DARS SCORES: CEMS/PEM DATA[a]

| Attribute | Emission Factor Score | Activity Data Score | Composite Scores | | Comment |
			Range	Midpoint	
Measurement/method	0.9 - 1	0.9 - 1	0.81 - 1	0.905	Lower scores given if relative accuracy poor (e.g., >10 percent) or data capture closer to 90 percent.
Source definition	1.0	1.0	1.0	1.0	
Spatial congruity	1.0	1.0	1.0	1.0	
Temporal congruity	1.0	1.0	1.0	1.0	
Weighted Score	0.98 - 1	0.98 - 1	0.95 - 1	0.98	

[a] Assumes data capture is 90 percent or better, and representative of entire year; monitors, sensors, and other equipment properly maintained.

The use of stack sample data can give DARS scores as high as those for CEMS/PEM data. However, the sample size is usually too low to be considered completely representative of the range of possible emissions making a score of 1.0 for measurement/method unlikely. A typical DARS score is generally closer to the low end of the range shown in Table 2.6-2.

Two examples are given for emissions calculated using emission factors. For both of these examples, the activity data are assumed to be measured directly or indirectly. Table 2.6-3 applies to an emission factor developed from CEMS/PEM data from one boiler and then applied to a different boiler of similar design and age. Table 2.6-4 gives an example for an estimate made with an *AP-42* emission factor. *AP-42* factors are defined for classes of boilers (based on size and fuel type); for some pollutants, the variability in emissions among this population may be high. The *AP-42* factor is a mean and could overestimate or underestimate emissions for any single boiler in the population. Also, the data on which some of these factors are based are often

TABLE 2.6-2

DARS SCORES: STACK SAMPLE DATA[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.7 - 1	0.7 - 1	0.49 - 1	0.745	
Source definition	1 - 1	1 - 1	1 - 1	1	
Spatial congruity	1 - 1	1 - 1	1 - 1	1	
Temporal congruity	0.7 - 1	0.7 - 1	0.49 - 1	0.745	Lower scores given if emissions vary temporally and sample does not cover range.
Weighted Score	0.85 - 1	0.85 - 1	0.75 - 1	0.87	

[a] Assumes use of an EPA reference method, high quality data.

limited in numbers and may be 10-20 years old. Thus, the confidence that can be placed in emissions estimated for a specific boiler with a general *AP-42* factor is lower than emissions based on source-specific data.

The example in Table 2.6-3 shows that emission factors based on high-quality data from a similar unit will typically give better results than a general factor. The main criterion affecting the score is how similar the boiler used to generate the factor is to the target boiler.

If sufficient data are available, the uncertainty in the estimate should be quantified. QA methods are described in the (Volume VI, Chapter 4).

TABLE **2.6-3**

DARS SCORES: SOURCE-SPECIFIC EMISSION FACTOR[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.9 - 1	0.8 - 1	0.72 - 1	0.86	Factor score for this attribute depends entirely on data quality.
Source definition	0.5 - 0.9	0.8 - 0.9	0.4 - 0.81	0.61	Factor score lowest if unit differs much from original source of data.
Spatial congruity	1 - 1	1 - 1	1 - 1	1	
Temporal congruity	1 - 1	0.5 - 0.9	0.5 - 0.9	0.7	
Weighted Score	0.85 - 0.98	0.78 - 0.95	0.66 - 0.93	0.79	

[a] Assumes factor developed from PEM or CEMS data from an identical emission unit (same manufacturer, model).

TABLE 2.6-4

DARS SCORES: AP-42 EMISSION FACTOR[a]

Attribute	Emission Factor Score	Activity Data Score	Composite Scores		Comment
			Range	Midpoint	
Measurement/method	0.6 - 0.8	0.8 - 1	0.48 - 0.7	0.59	Score depends on quality and quantity of data points used to develop factor.
Source definition	0.5 - 0.9	0.8 - 0.9	0.4 - 0.81	0.605	Emission factor score will be low if variability in source population is high.
Spatial congruity	0.6 - 0.8	1 - 1	0.6 - 0.8	0.7	Factor score lower if geographic location has significant effect on emissions.
Temporal congruity	0.5 - 0.9	0.5 - 0.9	0.25 - 0.81	0.53	Lower scores given if emissions vary temporally and sample does not cover range.
Weighted Score	0.55 - 0.85	0.78 - 0.95	0.43 - 0.78	0.61	

[a] Assumes activity data (e.g., fuel use) or surrogate is measured directly in some manner.

7

DATA CODING PROCEDURES

This section describes the methods and codes available for characterizing emission sources at boiler facilities using SCC and Aerometric Information Retrieval System (AIRS) control device codes. Consistent categorization and coding will result in greater uniformity among inventories. The SCCs are the building blocks on which point source emissions data are structured. Each SCC represents a unique process or function within a source category that is logically associated with an emission point. Without an appropriate SCC, a process cannot be accurately identified for retrieval purposes. In addition, the procedures described here will assist the reader preparing data for input to a database management system. For example, the use of the SCCs provided in Table 2.7-1 are recommended for describing boiler operations. Refer to the Clearinghouse for Inventories and Emission Factors (CHIEF) for a complete listing of SCCs for boilers. While the codes presented here are currently in use, they may change based on further refinement by the emission inventory user community. As part of the Emission Inventory Improvement Program (EIIP), a common emissions data exchange format is being developed to facilitate data transfer between industry, states, and EPA.

7.1 PROCESS EMISSIONS

Use of the codes in Table 2.7-1 are recommended for describing boilers that burn anthracite, bituminous, subbituminous, or lignite coal; oil- or natural gas-fired electric utility boilers; peaking plants; cogeneration units; and electric utility boilers that burn other types of fuel. More than one code may be necessary for each boiler if auxiliary fuel is used. Auxiliary fuels such as oil are used during start-up of utility boilers, or to sustain combustion (such as coal, oil, or natural gas used at utility boilers that predominantly burn wood/bark or waste).

7.2 STORAGE TANKS

The codes in Table 2.7-1 are recommended to describe emissions related to fuel storage.

7.3 FUGITIVE EMISSIONS

Fugitive emissions at boiler facilities may result from coal, wood/bark, and solid/liquid waste handling and storage. Limestone handling and storage emissions may also occur if the facility uses limestone in control devices such as scrubbers. There are undoubtedly sources of fugitive emissions within the facility or sources that have not been specifically discussed thus far; these

should be included. Conditions vary from plant to plant, so each specific case cannot be discussed within the context of this document.

Codes that may be used to describe fugitive emissions at boiler facilities are also presented in Table 2.7-1. It may be necessary to use a miscellaneous fugitive emission code for sources without a unique code. Many database systems used for inventory management contain a comment field that may be used to describe the fugitive emissions.

7.4 CONTROL DEVICES

The codes found in Table 2.7-2[1] are recommended for describing control devices used at electric utilities and may also be applicable to control devices used at commercial and institutional boilers. The "099" control code may be used to handle miscellaneous control devices that do not have a unique control equipment identification code. For a complete listing, the reader may consult the *AIRS User's Guide Volume XI: AFS Data Dictionary* (AFS is AIRS Facility Subsystem) (EPA, January 1992).

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[1] Note: At the time of publication, these control device codes were under review by the EPA. The reader should consult the EPA for the most current list of codes.

TABLE 2.7-1

SOURCE CLASSIFICATION CODES FOR BOILERS

Source Description	Process Description	SCC	Units
External Combustion Boilers			
External Combustion Boilers: Electric Generation	Pulverized Coal (Anthracite)	1-01-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite Coal)	1-01-001-02	Tons Anthracite Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-01-002-01	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-01-002-02	Tons Bituminous Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-01-002-03	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-01-002-04	Tons Bituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Bituminous Coal)	1-01-002-05	Tons Bituminous Coal Burned
	Wet Bottom (Tangential) (Bituminous Coal)	1-01-002-11	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-01-002-12	Tons Bituminous Coal Burned
	Cell Burner (Bituminous Coal)	1-01-002-15	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-01-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-01-002-18	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-01-002-21	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-01-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-01-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-01-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-01-002-25	Tons Subbituminous Coal Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-01-002-26	Tons Subbituminous Coal Burned
	Cell Burner (Subbituminous Coal)	1-01-002-35	Tons Subbituminous Coal Burned
	Atmospheric Fluidized Bed Combustion - Circulating Bed (subbitum coal)	1-01-002-38	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-01-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-01-003-01	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-01-003-02	Tons Lignite Burned
	Cyclone Furnace (Lignite)	1-01-003-03	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-01-003-04	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-01-003-06	Tons Lignite Burned
	Atmospheric Fluidized Bed (Lignite)** (See 101003-17 & -18)	1-01-003-16	Tons Lignite Burned
	Atmospheric Fluidized Bed Combustion - Bubbling Bed (Lignite)	1-01-003-17	Tons Lignite Burned
	Atmospheric Fluidized Bed Combustion - Circulating Bed (Lignite)	1-01-003-18	Tons Lignite Burned
	Normal Firing, Grade 6 Oil (Residual)	1-01-004-01	1000 Gallons Residual Oil Burned
	Tangential Firing, Grade 6 Oil (Residual)	1-01-004-04	1000 Gallons Residual Oil Burned
	Normal Firing, Grade 5 Oil (Residual)	1-01-004-05	1000 Gallons Residual Oil Burned
	Tangential Firing, Grade 5 Oil (Residual)	1-01-004-06	1000 Gallons Residual Oil Burned
	Grades 1 and 2 Oil (Distillate)	1-01-005-01	1000 Gallons Distillate Oil Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Normal Firing, Grade 4 Oil (Distillate)	1-01-005-04	1000 Gallons Distillate Oil Burned
	Tangential Firing, Grade 4 Oil (Distillate)	1-01-005-05	1000 Gallons Distillate Oil Burned
	Natural Gas Boilers > 100 Million Btu/hr except Tangential	1-01-006-01	Million Cubic Feet Natural Gas Burned
	Natural Gas Boilers < 100 Million Btu/hr except Tangential	1-01-006-02	Million Cubic Feet Natural Gas Burned
	Natural Gas Boilers: Tangentially Fired Units	1-01-006-04	Million Cubic Feet Natural Gas Burned
	Process Gas Boilers > 100 Million Btu/hr	1-01-007-01	Million Cubic Feet Process Gas Burned
	Process Gas Boilers < 100 Million Btu/hr	1-01-007-02	Million Cubic Feet Process Gas Burned
	Coke, All Boiler Sizes	1-01-008-01	Tons Coke Burned
	Bark-fired Boiler (Wood/Bark Waste)	1-01-009-01	Tons Bark Burned
	Wood/Bark Fired Boiler (Wood/Bark Waste)	1-01-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (Wood/Bark Waste)	1-01-009-03	Tons Wood Burned
	Fuel cell/Dutch oven boilers (Wood/Bark Waste)	1-01-009-10	Ton Wood/Bark Burned
	Stoker boilers (Wood/Bark Waste)	1-01-009-11	Ton Wood/Bark Burned
	Fluidized bed combustion boilers (Wood/Bark Waste)	1-01-009-12	Ton Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-01-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-01-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-01-010-03	1000 Gallons Propane/Butane Burned
	Bagasse, All Boiler Sizes	1-01-011-01	Tons Bagasse Burned
	Solid Waste, Specify Material in Comments	1-01-012-01	Tons Solid Waste Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Electric Generation (Continued)	Solid Waste, Refuse Derived Fuel	1-01-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-01-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-01-013-02	1000 Gallons Waste Oil Burned
	Geothermal Power Plants: Off-Gas Ejectors	1-01-015-01	Megawatt-Hour Electricity Produced
	Geothermal Power Plants: Cooling Tower Exhaust	1-01-015-02	Megawatt-Hour Electricity Produced
External Combustion Boilers: Industrial Boilers	Pulverized Coal (Anthracite)	1-02-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite)	1-02-001-04	Tons Anthracite Coal Burned
	Hand-fired (Anthracite)	1-02-001-07	Tons Anthracite Coal Burned
	Fluidized Bed Boiler Burning Anthracite-Culm Fuel	1-02-001-17	Tons Anthracite Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-02-002-01	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-02-002-02	Tons Bituminous Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-02-002-03	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-02-002-04	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-02-002-05	Tons Bituminous Coal Burned
	Underfeed Stoker (Bituminous Coal)	1-02-002-06	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-02-002-10	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-02-002-12	Tons Bituminous Coal Burned
	Wet Slurry (Bituminous Coal)	1-02-002-13	Tons Bituminous Coal Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-02-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-02-002-18	Tons Bituminous Coal Burned
	Cogeneration (Bituminous Coal)	1-02-002-19	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-02-002-21	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-02-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-02-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-02-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-02-002-25	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-02-002-26	Tons Subbituminous Coal Burned
	Cogeneration (Subbituminous Coal)	1-02-002-29	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-02-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-02-003-01	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-02-003-02	Tons Lignite Burned
	Cyclone Furnace (Lignite)	1-02-003-03	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-02-003-04	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-02-003-06	Tons Lignite Burned
	Cogeneration (Lignite)	1-02-003-07	Tons Lignite Burned
	Grade 6 Oil (Residual)	1-02-004-01	1000 Gallons Residual Oil Burned
	10-100 Million Btu/hr, (Residual Oil)	1-02-004-02	1000 Gallons Residual Oil Burned
	< 10 Million Btu/hr, (Residual Oil)	1-02-004-03	1000 Gallons Residual Oil Burned
	Grade 5 Oil (Residual)	1-02-004-04	1000 Gallons Residual Oil Burned
	Cogeneration (Residual Oil)	1-02-004-05	1000 Gallons Residual Oil Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Grades 1 and 2 Oil (Distillate)	1-02-005-01	1000 Gallons Distillate Oil Burned
	10-100 Million Btu/hr, (Distillate Oil)	1-02-005-02	1000 Gallons Distillate Oil Burned
	< 10 Million Btu/hr, (Distillate Oil)	1-02-005-03	1000 Gallons Distillate Oil Burned
	Grade 4 Oil (Distillate)	1-02-005-04	1000 Gallons Distillate Oil Burned
	Cogeneration (Distillate Oil)	1-02-005-05	1000 Gallons Distillate Oil Burned
	> 100 Million Btu/hr, (Natural Gas)	1-02-006-01	Million Cubic Feet Natural Gas Burned
	10-100 Million Btu/hr, (Natural Gas)	1-02-006-02	Million Cubic Feet Natural Gas Burned
	< 10 Million Btu/hr, (Natural Gas)	1-02-006-03	Million Cubic Feet Natural Gas Burned
	Cogeneration (Natural Gas)	1-02-006-04	Million Cubic Feet Natural Gas Burned
	Petroleum Refinery, (Process Gas)	1-02-007-01	Million Cubic Feet Process Gas Burned
	Blast Furnace, (Process Gas)	1-02-007-04	Million Cubic Feet Process Gas Burned
	Coke Oven, (Process Gas)	1-02-007-07	Million Cubic Feet Process Gas Burned
	Cogeneration (Process Gas)	1-02-007-10	Million Cubic Feet Process Gas Burned
	Other: Specify in Comments (Process Gas)	1-02-007-99	Million Cubic Feet Process Gas Burned
	All Boiler Sizes, (Coke)	1-02-008-02	Tons Coke Burned
	Cogeneration (Coke)	1-02-008-04	Tons Coke Burned
	Bark-fired Boiler (> 50,000 Lb Steam)	1-02-009-01	Tons Bark Burned
	Wood/Bark-fired Boiler (> 50,000 Lb Steam)	1-02-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (> 50,000 Lb Steam)	1-02-009-03	Tons Wood Burned
	Bark-fired Boiler (< 50,000 Lb Steam)	1-02-009-04	Tons Bark Burned
	Wood/Bark-fired Boiler (< 50,000 Lb Steam)	1-02-009-05	Tons Wood/Bark Burned
	Wood-fired Boiler (< 50,000 Lb Steam)	1-02-009-06	Tons Wood Burned
	Cogeneration (Wood)	1-02-009-07	Tons Wood Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Boilers (Continued)	Fuel cell/Dutch oven boilers	1-02-009-10	Tons Wood/Bark Burned
	Stoker boilers	1-02-009-11	Tons Wood/Bark Burned
	Fluidized bed combustion boiler	1-02-009-12	Tons Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-02-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-02-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-02-010-03	1000 Gallons Propane/Butane Burned
	Bagasse, All Boiler Sizes	1-02-011-01	Tons Bagasse Burned
	Solid Waste, Specify Material in Comments	1-02-012-01	Tons Solid Waste Burned
	Solid Waste, Refuse Derived Fuel	1-02-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-02-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-02-013-02	1000 Gallons Waste Oil Burned
	CO Boiler (Natural Gas)	1-02-014-01	Million Cubic Feet Natural Gas Burned
	CO Boiler (Process Gas)	1-02-014-02	Million Cubic Feet Process Gas Burned
	CO Boiler (Distillate Oil)	1-02-014-03	1000 Gallons Distillate Oil Burned
	CO Boiler (Residual Oil)	1-02-014-04	1000 Gallons Residual Oil Burned
	Methanol, Industrial Boiler	1-02-016-01	1000 Gallons Methanol Burned
	Gasoline, Industrial Boiler	1-02-017-01	1000 Gallons Gasoline Burned
External Combustion Boilers: Industrial Space Heating	Space Heaters (Coal)	1-05-001-02	Tons Coal Burned
	Space Heaters (Distillate Oil)	1-05-001-05	1000 Gallons Distillate Oil Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Industrial Space Heating (Continued)	Space Heaters (Natural Gas)	1-05-001-06	Million Cubic Feet Natural Gas Burned
	Space Heaters (Liquified Petroleum Gas)	1-05-001-10	1000 Gallons LPG Burned
	Space Heaters, Air Atomized Burner (Waste Oil)	1-05-001-13	1000 Gallons Waste Oil Burned
	Space Heaters, Vaporizing Burner (Waste Oil)	1-05-001-14	1000 Gallons Waste Oil Burned
External Combustion Boilers: Commercial/ Institutional Boilers	Pulverized Coal (Anthracite)	1-03-001-01	Tons Anthracite Coal Burned
	Traveling Grate (Overfeed) Stoker (Anthracite Coal)	1-03-001-02	Tons Anthracite Coal Burned
	Hand-fired (Anthracite)	1-03-001-03	Tons Anthracite Coal Burned
	Cyclone Furnace (Bituminous Coal)	1-03-002-03	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Bituminous Coal)	1-03-002-05	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Bituminous Coal)	1-03-002-06	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-03-002-07	Tons Bituminous Coal Burned
	Underfeed Stoker (Bituminous Coal)	1-03-002-08	Tons Bituminous Coal Burned
	Spreader Stoker (Bituminous Coal)	1-03-002-09	Tons Bituminous Coal Burned
	Overfeed Stoker (Bituminous Coal)	1-03-002-11	Tons Bituminous Coal Burned
	Hand-fired (Bituminous Coal)	1-03-002-14	Tons Bituminous Coal Burned
	Pulverized Coal: Dry Bottom (Tangential) (Bituminous Coal)	1-03-002-16	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Bubbling Bed (Bituminous Coal)	1-03-002-17	Tons Bituminous Coal Burned
	Atmospheric Fluidized Bed Combustion: Circulating Bed (Bitum. Coal)	1-03-002-18	Tons Bituminous Coal Burned
	Pulverized Coal: Wet Bottom (Subbituminous Coal)	1-03-002-21	Tons Subbituminous Coal Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Boilers (Continued)	Pulverized Coal: Dry Bottom (Subbituminous Coal)	1-03-002-22	Tons Subbituminous Coal Burned
	Cyclone Furnace (Subbituminous Coal)	1-03-002-23	Tons Subbituminous Coal Burned
	Spreader Stoker (Subbituminous Coal)	1-03-002-24	Tons Subbituminous Coal Burned
	Traveling Grate (Overfeed) Stoker (Subbituminous Coal)	1-03-002-25	Tons Subbituminous Coal Burned
	Pulverized Coal: Dry Bottom Tangential (Subbituminous Coal)	1-03-002-26	Tons Subbituminous Coal Burned
	Pulverized Coal: Wet Bottom (Lignite)	1-03-003-00	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Wall Fired (Lignite)	1-03-003-05	Tons Lignite Burned
	Pulverized Coal: Dry Bottom, Tangential Fired (Lignite)	1-03-003-06	Tons Lignite Burned
	Traveling Grate (Overfeed) Stoker (Lignite)	1-03-003-07	Tons Lignite Burned
	Spreader Stoker (Lignite)	1-03-003-09	Tons Lignite Burned
	Grade 6 Oil (Residual)	1-03-004-01	1000 Gallons Residual Oil Burned
	10-100 Million Btu/hr, (Residual Oil)	1-03-004-02	1000 Gallons Residual Oil Burned
	< 10 Million Btu/hr, (Residual Oil)	1-03-004-03	1000 Gallons Residual Oil Burned
	Grade 5 Oil (Residual)	1-03-004-04	1000 Gallons Residual Oil Burned
	Grades 1 and 2 Oil (Distillate)	1-03-005-01	1000 Gallons Distillate Oil Burned
	10-100 Million Btu/hr, (Distillate Oil)	1-03-005-02	1000 Gallons Distillate Oil Burned
	< 10 Million Btu/hr, (Distillate Oil)	1-03-005-03	1000 Gallons Distillate Oil Burned
	Grade 4 Oil (Distillate)	1-03-005-04	1000 Gallons Distillate Oil Burned
	> 100 Million Btu/hr, (Natural Gas)	1-03-006-01	Million Cubic Feet Natural Gas Burned
	10-100 Million Btu/hr, (Natural Gas)	1-03-006-02	Million Cubic Feet Natural Gas Burned
	< 10 Million Btu/hr, (Natural Gas)	1-03-006-03	Million Cubic Feet Natural Gas Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Boilers (Continued)	POTW Digester Gas-fired Boiler (Process Gas)	1-03-007-01	Million Cubic Feet Process Gas Burned
	Other Not Classified (Process Gas)	1-03-007-99	Million Cubic Feet Process Gas Burned
	Landfill Gas	1-03-008-11	Million Cubic Feet Landfill Gas Burned
	Bark-fired Boiler (Wood/Bark Waste)	1-03-009-01	Tons Bark Burned
	Wood/Bark-fired Boiler (Wood/Bark Waste)	1-03-009-02	Tons Wood/Bark Burned
	Wood-fired Boiler (Wood/Bark Waste)	1-03-009-03	Tons Wood Burned
	Fuel cell/Dutch oven boilers (Wood/Bark Waste)	1-03-009-10	Tons Wood/Bark Burned
	Stoker boilers (Wood/Bark Waste)	1-03-009-11	Tons Wood/Bark Burned
	Fluidized bed combustion boilers (Wood/Bark Waste)	1-03-009-12	Tons Wood/Bark Burned
	Liquified Petroleum Gas (LPG), Butane	1-03-010-01	1000 Gallons Butane Burned
	Liquified Petroleum Gas (LPG), Propane	1-03-010-02	1000 Gallons Propane Burned
	Liquified Petroleum Gas (LPG), Butane/Propane Mixture: Specify Percent Butane in Comments	1-03-010-03	1000 Gallons Propane/Butane Burned
	Solid Waste, Specify Material in Comments	1-03-012-01	Tons Solid Waste Burned
	Solid Waste, Refuse Derived Fuel	1-03-012-02	Tons Refuse Derived Fuel Burned
	Liquid Waste, Specify Waste in Comments	1-03-013-01	1000 Gallons Liquid Waste Burned
	Liquid Waste, Waste Oil	1-03-013-02	1000 Gallons Waste Oil Burned
	Liquid Waste, Sewage Grease Skimmings	1-03-013-03	1000 Gallons Sewage Grease Skimmings Burned

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
External Combustion Boilers (Continued)			
External Combustion Boilers: Commercial/ Institutional Space Heating	Space Heaters (Coal)	1-05-002-02	Tons Coal Burned
	Space Heaters (Distillate Oil)	1-05-002-05	1000 Gallons Distillate Oil Burned
	Space Heaters (Natural Gas)	1-05-002-06	Million Cubic Feet Natural Gas Burned
	Space Heaters (Wood)	1-05-002-09	Tons Wood Burned
	Space Heaters (Liquified Petroleum Gas)	1-05-002-10	1000 Gallons LPG Burned
	Space Heaters, Air Atomized Burner (Waste Oil)	1-05-002-13	1000 Gallons Waste Oil Burned
	Space Heaters, Vaporizing Burner (Waste Oil)	1-05-002-14	1000 Gallons Waste Oil Burned
Waste Disposal			
Waste Disposal: Solid Waste Landfill	Waste Gas Recovery: Boiler	5-01-004-23	Million Cubic Feet Waste Gas Burned
Waste Disposal: Site Remediation	Thermal Destruction Combustion Unit: Boiler	5-04-105-37	Tons Feed Material Processed
Miscellaneous Industrial Processes with Applicable Codes			
Carbon Black Production	Main Process Vent with CO Boiler and Incinerator	3-01-005-10	Tons Carbon Black Produced
Integrated Iron and Steel Manufacturing	Miscellaneous Combustion Sources: Boilers	3-03-015-82	Tons Material Produced
Sulfate (Kraft) Pulping	Boiler Ash Handling	3-07-001-19	Tons Ash Handled
Fuel Storage and Transfer			
Petroleum Liquids Storage (non-Refinery)	Underground Tanks, Breathing Loss (No. 2 Distillate Oil)	4-04-004-13	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Underground Tanks, Working Loss (No. 2 Distillate Oil)	4-04-004-14	1000 Gallons No. 2 Distillate Oil Throughput
	Underground Tanks, Breathing Loss (Specify Liquid)	4-04-004-97	1000 Gallons Liquid Storage Capacity
	Underground Tanks, Working Loss (Specify Liquid)	4-04-004-98	1000 Gallons Liquid Throughput

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Fuel Storage and Transfer (Continued)			
Industrial Processes, In-Process Fuel Use	Fixed Roof Tanks, Breathing Loss (Residual Oil)	3-90-900-01	1000 Gallons Residual Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (Residual Oil)	3-90-900-02	1000 Gallons Residual Oil Throughput
	Fixed Roof Tanks, Breathing Loss (No. 2 Distillate Oil)	3-90-900-03	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (No. 2 Distillate Oil)	3-90-900-04	1000 Gallons No. 2 Distillate Oil Throughput
	Fixed Roof Tanks, Breathing Loss (No. 6 Oil)	3-90-900-05	1000 Gallons No. 6 Residual Oil Storage Capacity
	Fixed Roof Tanks, Working Loss (No. 6 Oil)	3-90-900-06	1000 Gallons No. 6 Residual Oil Throughput
	Floating Roof Tanks, Standing Loss (Residual Oil)	3-90-910-01	1000 Gallons Residual Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (Residual Oil)	3-90-910-02	1000 Gallons Residual Oil Throughput
	Floating Roof Tanks, Standing Loss (No. 2 Distillate Oil)	3-90-910-03	1000 Gallons No. 2 Distillate Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (No. 2 Distillate Oil)	3-90-910-04	1000 Gallons No. 2 Distillate Oil Throughput
	Floating Roof Tanks, Standing Loss (No. 6 Oil)	3-90-910-05	1000 Gallons No. 6 Residual Oil Storage Capacity
	Floating Roof Tanks, Withdrawal Loss (No. 6 Oil)	3-90-910-06	1000 Gallons No. 6 Residual Oil Throughput
	Pressure Tanks, Withdrawal Loss (Natural Gas)	3-90-920-50	1000 Gallons Natural Gas Throughput

TABLE 2.7-1

(CONTINUED)

Source Description	Process Description	SCC	Units
Fuel Storage and Transfer: (Continued)			
Industrial Processes, In-Process Fuel Use (Continued)	Pressure Tanks, Withdrawal Loss (Liquified Petroleum Gas)	3-90-920-51	1000 Gallons LPG Throughput
	Pressure Tanks, Withdrawal Loss (Landfill Gas)	3-90-920-52	1000 Gallons Landfill Gas Throughput
	Pressure Tanks, Withdrawal Loss (Digester Gas)	3-90-920-54	1000 Gallons Digester Gas Throughput
	Pressure Tanks, Withdrawal Loss (Process Gas)	3-909-20-55	1000 Gallons Process Gas Throughput

TABLE 2.7-2

AIRS CONTROL DEVICE CODES

Control Device	Code
Wet Scrubber - High-Efficiency	001
Wet Scrubber - Medium-Efficiency	002
Wet Scrubber - Low-Efficiency	003
Gravity Collector - High-Efficiency	004
Gravity Collector - Medium-Efficiency	005
Gravity Collector - Low-Efficiency	006
Centrifugal Collector - High-Efficiency	007
Centrifugal Collector - Medium-Efficiency	008
Centrifugal Collector - Low-Efficiency	009
Electrostatic Precipitator - High-Efficiency	010
Electrostatic Precipitator - Medium-Efficiency	011
Electrostatic Precipitator - Low-Efficiency	012
Fabric Filter - High-Efficiency	016
Fabric Filter - Medium-Efficiency	017
Fabric Filter - Low-Efficiency	018
Mist Eliminator - High-Velocity	014
Mist Eliminator - Low-Velocity	015
Modified Furnace or Burner Design	024
Staged Combustion	025
Flue Gas Recirculation	026
Reduced Combustion-Air Preheating	027
Steam or Water Injection	028

TABLE 2.7-2

(CONTINUED)

Control Device	Code
Low-Excess Air Firing	029
Use of Fuel with Low Nitrogen Content	030
Catalytic Reduction	065
Selective Noncatalytic Reduction for NO_x	107
Catalytic Oxidation - Flue Gas Desulfurization	039
Dry Limestone Injection	041
Wet Limestone Injection	042
Venturi Scrubber	053
Wet Lime Slurry Scrubbing	067
Alkaline Fly Ash Scrubbing	068
Sodium Carbonate Scrubbing	069
Miscellaneous Control Device	099

Note: At the time of publication, these control device codes were under review by the EPA. The reader should consult the EPA for the most current list of codes.

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8

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